EPCOR RESPONSES TO OEB STAFF INTERROGATORIES

EPCOR Natural Gas Limited Partnership

Application for 2020 to 2024 Rates

EB-2018-0336

1-STAFF-1

Reference: **Exhibit 1 / Tab 1 / Schedule 1/ Pg.6**

Request:

Please confirm that the correct requested revenue requirement is $6,652,600 and not $6,665,600 as indicated in the above reference.

Response:

EPCOR Natural Gas LP ("ENGLP") is requesting a revenue requirement of $6,740,568 based on updates to the Application as outline in 9-STAFF-78.

1-STAFF-2

Reference: **Exhibit 1 / Tab 1 / Schedule 1/ Pgs. 30 and 39 and Exhibit 4 / Tab 1 / Sch.1/**
Pg.5 / Table 4.1-8

Request:

EPCOR Natural Gas LP (EPCOR) has provided two different values representing gas transportation costs for 2020 ($674,644 – pg. 39 and $675,544 – pg.30).

Please reconcile the two and identify the correct number.

Response:

The correct value for gas transportation costs for 2020 is $675,544. The $674,644 is the gas transportation value for 2019.

ENGLP inadvertently inserted the values for 2019 when populating Table 1.5.5-4 in Exhibit 1. As a result, Table 1.5.5-4, which identifies values for 2020 are the forecast values for 2019. Table 4.1-8 (Exhibit 4, Tab 1, Schedule 1, page 5) includes the correct values for 2020. Table 4.1-7 includes the values for 2019 that were used to populate Table 1.5.5-4.

1-STAFF-3

Reference: **Exhibit 1 / Tab 1 / Schedule 1/ Pg. 39 and Exhibit 4 / Tab 1 / Sch. 4/ Pgs.4-5**

Request:

Two different values appear in different sections representing 2019 gas transportation costs ($970,411 and $674,644). The amount of $970,411 is also shown for 2018 gas transportation costs (Exhibit 4, Table 4.1-6).

Please reconcile the numbers and confirm the appropriate gas transportation costs for 2018 and 2019. If updated numbers are available, please revise them accordingly.

Response:

The correct value for gas transportation costs for 2019 is $674,644. The $970,411 is the gas transportation value for 2018.

ENGLP inadvertently inserted the values for 2018 when populating Table 1.5.5-3 in Exhibit 1, Tab 1, Schedule 1. As a result, Table 1.5.5-3, which identifies values for 2019 are the forecast values for 2018. Table 4.1-7 (Exhibit 4, Tab 1, Schedule 1, page 5) includes the correct values for 2019. Table 4.1-6 (Exhibit 4, Tab 1, Schedule 1, page 4) includes the values for 2018 that were used to populate Table 1.5.5-3.

Updated gas transportation numbers for 2018 have been provided in response to 4-STAFF-42(a). The updated values have also been inserted into the table below for reference.

Table 1-STAFF-3-1
2018 Commodity and Transportation Costs

	Gas Commodity	A **m3**	B **$**	C **cent / m3**
1	Enbridge Gas	27,413,966	4,165,946	15.1964
2	Local Production A	976,058	293,989	30.1200
3	Local Production B	115,783	15,127	13.0646
4	Gas Inventory Revaluation		165,797	
5	PGCVA		41,088	
6	**Total Gas Commodity Cost**	**28,505,807**	**4,681,946**	**16.4245**
8	Enbridge excl. IGPC	29,888,961	624,394	2.0890
9	IGPC	39,464,980	551,101	1.3964
7	Unaccounted For Gas	-	-197,375	-
10	**Total Gas Transportation Cost**	**69,353,941**	**978,120**	**1.4103**
11	**Total Gas Commodity and Transportation Cost**		**5,660,067**	

Updated numbers for Table 1.5.5-3 (2019) are as follows:

Table 1-STAFF-3-2
Table 1.5.5-3 (Updated)
ENGLP 2019 Gas Supply and Transportation Costs

	Gas Commodity	A **m3**	B **$**	C **cents / m3**
1	Enbridge Gas	24,309,669	4,248,503	17.4766
2	Local Production A	1,000,000	301,200	30.1200
3	Local Production B	657,417	114,894	17.4766
4	**Total Gas Commodity Cost**	**25,967,085**	**4,664,597**	**17.9635**
5	Unaccounted For Gas	-	-	-
6	**Total Gas Transportation Cost**	**26,325,152**	**674,644**	**2.5627**
7	**Total Gas Commodity and Transportation Cost**		**5,339,242**	

1-STAFF-4
Reference: **Exhibit 1 / Tab 1 / Schedule 1/ Pg.9**

Request:

Following publication of the Notice of Application and the community meeting, consumers have the opportunity to file letters of comment with respect to the application. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment.

Please file a response to the matters raised in the letters of comment that were also copied to EPCOR. Going forward, please ensure that responses to any matters raised in subsequent comments or letters that the applicant receives are filed in this proceeding. Please ensure that name and contact information is redacted for public filings. All responses must be filed before the final argument (submission) phase of this proceeding.

Response:

As of the time of filing this response, ENGLP has not received any letters of comment with respect to this Application. Going forward, ENGLP will ensure that responses to any matters raised in consumer comments or letters that it receives are filed in this proceeding, in accordance with filing requirements.

1-STAFF-5
Reference: **Exhibit 1/ Tab1/ Schedule 1/ Pg. 47**

Request:

EPCOR has indicated that it may file a separate application annually, requesting to dispose of its deferral and variance accounts. Please explain why EPCOR is not planning to request the disposition of deferral and variance accounts in the same application as its IR applications for regulatory efficiency purposes.

Response:

ENGLP will continue to deal with the balances in the Purchased Gas Commodity Variance Account ("PGCVA") and Gas Purchase Rebalancing Account ("GPRA") through its Quarterly Rate Adjustment Mechanism ("QRAM") applications as outlined in Section 9.1.1 in Exhibit 9, Tab 1, Schedule 1, page 4. For clarity, ENGLP intends to bring all other deferral and variance accounts ("DVA") forward for disposition as a part of its annual Price Cap IR application unless otherwise directed by the Board as in the case of the DVA's related to greenhouse gas emissions.

1-STAFF-6
Reference: **Exhibit 1/ Tab 1/ Schedule 1/Pg. 61**

Request:

Please provide the 2018 audited financial statements. If not available, please provide the 2018 preliminary financial statements. Please provide a reconciliation between the financial statements and regulatory statements.

Response:

ENGLP's 2018 audited financial statements and the reconciliation between the financial statements and regulatory statements have been provided in 1-STAFF-6 Attachment 1 and Attachment 2, respectively.

Financial Statements of

EPCOR Natural Gas Limited Partnership

Years ended December 31, 2018 and 2017

Independent Auditors' Report 1

Financial Statements:

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
EPCOR Ontario Utilities Inc.

Opinion

We have audited the financial statements of EPCOR Natural Gas Limited Partnership (the Entity), which comprise the statement of financial position as at December 31, 2018, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

London, Ontario
April 3, 2019

EPCOR Natural Gas Limited Partnership

Statements of Comprehensive Income
(In thousands of Canadian dollars)

Years ended December 31, 2018 and 2017

		2018		2017
Revenue (note 5)	$	12,111	$	3,217
Operating expenses:				
Energy purchases		4,483		1,377
Staff costs and employee benefits expenses		1,239		218
Depreciation and amortization (note 6)		862		190
Other raw materials and operating charges		1,541		174
Franchise fees and property taxes		573		100
Other administrative expenses		2,918		1,566
		11,616		3,625
Operating income (loss)		495		(408)
Finance expenses		(354)		(24)
Comprehensive income (loss) for the year - all attributable to the Partners	$	141	$	(432)

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statements of Financial Position
(In thousands of Canadian dollars)

December 31, 2018 and 2017

	2018	2017
ASSETS		
Current assets:		
Cash	$ 1,095	$ 2,408
Trade and other receivables (note 7)	1,945	2,221
Prepaid expenses	88	358
Inventories (note 8)	79	82
	3,207	5,069
Non-current assets:		
Property, plant and equipment (note 9)	19,487	17,857
Intangible assets (note 10)	1,143	1,207
Goodwill (note 10)	1,808	1,886
	22,438	20,950
TOTAL ASSETS	$ 25,645	$ 26,019
LIABILITIES AND EQUITY		
Current liabilities:		
Loans and borrowings (note 12)	$ 1,055	$ 3,153
Trade and other payables (note 11)	2,590	1,143
Customer deposits	78	103
Deferred revenue (note 13)	3	-
Provisions (note 14)	64	19
	3,790	4,418
Non-current liabilities:		
Loans and borrowings (note 12)	8,660	8,660
Deferred revenue (note 13)	113	13
	8,773	8,673
Total liabilities	12,563	13,091
Equity attributable to the Partners:		
Partnership units (note 15)	13,360	13,360
Deficit	(278)	(432)
Total equity – attributable to the Partners	13,082	12,928
TOTAL LIABILITIES AND EQUITY	$ 25,645	$ 26,019

Approved on behalf of the EPCOR Ontario Utilities Inc. Board of Directors,

Stuart Lee
Director, EPCOR Ontario Utilities Inc.

Steve Stanley
Director, EPCOR Ontario Utilities Inc.

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statements of Changes in Equity
(In thousands of Canadian dollars)

December 31, 2018 and 2017

	Partnership units (note 15)	Retained earnings (deficit)	Equity attributable to the Partners
Equity at December 31, 2016	$ 1	$ -	$ 1
Equity contribution from the Partners	13,359	-	13,359
Comprehensive loss for the year	-	(432)	(432)
Equity at December 31, 2017	13,360	(432)	12,928
Impact of changes in accounting policies (note 3(k))	-	13	13
Adjusted equity at December 31, 2017	13,360	(420)	12,940
Comprehensive income for the year	-	141	141
Equity at December 31, 2018	$ 13,360	$ (278)	$ 13,082

The accompanying notes are an integral part of these financial statements

EPCOR Natural Gas Limited Partnership

Statements of Cash Flows
(In thousands of Canadian dollars)

Years ended December 31, 2018 and 2017

	2018	2017
Cash flows from (used in) operating activities:		
Comprehensive income/(loss) for the year	$ 141	$ (432)
Reconciliation of comprehensive income/(loss) for the year to cash from (used in) operating activities:		
Depreciation and amortization (note 6)	862	190
Deferred revenue recognized (note 13)	(1)	-
Cash contributions received (note 13)	104	13
Finance expenses (net)	354	24
Interest paid (net)	(354)	(24)
Change in employee benefits provisions (note 14)	45	16
Net cash flows from (used in) operating activities before non-cash operating working capital changes	1,151	(213)
Changes in non-cash operating working capital (note 16)	1,984	54
Net cash flows from (used in) operating activities	3,135	(159)
Cash flows from (used in) investing activities:		
Acquisition or construction of property, plant and equipment (note 9)	(2,412)	(546)
Acquisition of intangible assets (note 10)	(21)	(41)
Proceeds on disposal of property, plant and equipment	5	-
Business acquisition (note 23)	78	(22,019)
Net cash flows used in investing activities	(2,350)	(22,606)
Cash flows from (used in) financing activities:		
Net (repayment)/issuance of short-term loans and borrowings (note 17)	(2,098)	3,153
Proceeds from issuance of long-term loans and borrowings (note 17)	-	8,660
Equity contributions from the Partners (note 15)	-	13,360
Net cash flows (used in)/from financing activities	(2,098)	25,173
Change in cash	(1,313)	2,408
Cash, beginning of year	2,408	-
Cash, end of year	$ 1,095	$ 2,408

The accompanying notes are an integral part of these financial statements

1. Description of business

(a) Nature of operations

EPCOR Natural Gas Limited Partnership (the Partnership or ENGLP) provides natural gas distribution service through its general partner EPCOR Ontario Utilities Inc. (the General Partner or EOUI) and operates within Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The Limited Partnership was formed on November 4, 2016 pursuant to a Certificate of Limited Partnership and a limited partnership agreement entered into between the General Partner and EPCOR Power Development Corporation (the Limited Partner) dated as of November 4, 2016 and operates in Ontario with its registered head office located at 77 King Street West, Suite 400, Toronto, Ontario M5K 0A1.

ENGLP is a limited partnership registered in Canada and is managed by the General Partner. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% owned by EPCOR Utilities Inc. (EPCOR).

(b) Rate regulation

The Partnership's operations are regulated by the OEB pursuant to *The Ontario Energy Board Act* (Ontario), *The Energy Act* (Ontario) and regulations made under those statutes. The OEB administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Partnership on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the natural gas distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the natural gas industry such as transition costs and other regulatory assets. All requests for change in natural gas distribution charges require the approval of the OEB.

Regulatory developments in Ontario's natural gas industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. ENGLP is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The Partnership did not adopt IFRS 14 – *Regulatory Deferral Accounts* (IFRS 14) during the Partnership's initial adoption of IFRS.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS). These financial statements were approved and authorized for issue by the Board of Directors of EOUI on April 3, 2019.

(b) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars and all rounded to the nearest thousand dollars, except where otherwise stated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

(a) Changes in significant accounting policies

The Partnership adopted new accounting standards and amendments to various accounting standards effective January 1, 2018, which resulted in changes to these financial statements. The changes from adoption of the new and revised standards are summarized below.

The Partnership adopted IFRS 9 - *Financial Instruments* (IFRS 9), which replaces IAS 39 – *Financial instruments: Recognition and Measurement* and IFRS 15 - *Revenue from Contracts with Customers* (IFRS 15), which replaces IAS 11 – *Construction Contracts,* and IAS 18 – *Revenue* and related interpretations, using the modified retrospective approach with the cumulative effect of any adjustments recognized in the opening balance of retained earnings as of January 1, 2018. The comparative information has not been restated and continues to be reported under previous accounting standards. The Partnership's updated accounting policies resulting from implementation of the new standards, along with analysis of the changes from the previous accounting policies, are set out in notes 3(c), 3(h), 3(j) and 3(k).

(b) Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The determination of whether or not an acquisition meets the definition of business combination under IFRS requires judgment and is assessed on a case-by-case basis. The consideration for an acquisition is measured at the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. The consideration transferred does not include amounts related to the settlement of pre-existing relationships. Such amounts are recognized in comprehensive income. Transaction costs that the Partnership incurs in connection with a business combination, other than those associated with the issue of debt or equity securities, are expensed as incurred.

Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Any contingent consideration payable is measured at fair value at the acquisition date. If the contingent consideration is classified as equity then it is not re-measured and settlement is accounted for within equity. Subsequent changes in the fair value of contingent consideration that is not classified as equity are recognized in comprehensive income.

Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Subsequently, goodwill is measured at cost less accumulated impairment losses, if any. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the carrying amount may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit (CGU) to which goodwill relates. Where the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized.

(c) Revenue recognition

Effective January 1, 2018, the Partnership recognizes revenue when it transfers control over a promised good or service, a performance obligation under the contract, to a customer and where the Partnership is entitled to consideration resulting from completion of the performance obligation. Depending on the terms of the contract with the customer, revenue recognition can occur at a point in time or over time. When a performance obligation is satisfied, revenue is measured at the transaction price that is allocated to that performance obligation. For contracts where non-cash consideration is received, revenue is recognized and measured at the fair value of the non-cash consideration.

Customer contracts may include the transfer of multiple goods and services. Where the Partnership determines that the multiple goods and services are not distinct performance obligations, they are treated as single performance obligation.

Revenue is classified as natural gas sales and provision of services depending on the nature of each distinct performance obligation.

Contract costs for obtaining a customer contract are expensed as incurred unless they create an asset related to future contract activity that the Partnership expects to recover.

Significant judgement may be required to determine the number of distinct performance obligations within a contract and the allocation of transaction price to multiple performance obligations in a contract, and to determine whether the Company acts as a principal or agent for certain performance obligations. When multiple performance obligations are identified in a contract, the transaction price is allocated based on the stand-alone selling price of each performance obligation. If stand-alone selling price is not observable, the Company estimates the stand-alone selling price for each distinct performance obligation based on the related expected cost plus margin. The Company is acting as a principal when the Company controls the goods or services before transfer to the customer. The Company is acting as an agent when it is obliged to arrange for the provision of the goods and services by another party that are not controlled by the Company before transfer to the customer. When the Company acts as an agent, the revenue is recognized net of any related costs incurred.

The Partnership's principal sources of revenue and methods applied to the recognition of these revenues in these financial statements are as follows:

Natural gas sales

The contracts with customers for the supply of natural gas consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership provides a series of distinct goods, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. the units of each good supplied to the customer.

Revenues are calculated based on the customer's usage of the goods during the period, at the applicable rates as per the terms of the respective contracts. Customers are generally billed on a monthly basis and payment is generally due within 30 days of billing the customer.

Provision of services

The contracts with customers for each of natural gas transmission and distribution services consist primarily of perpetual contracts that are effective until terminated by the customer or the Partnership. The Partnership provides a series of distinct services, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for recognition of revenue, i.e. quantifiable services rendered to the customer.

Revenues are calculated based on the services provided to the customer during the period, at the applicable rates as per the terms of the respective contracts. These revenues include an estimate of the value of services provided to the customers in the reporting period and billed subsequent to the reporting period. Customers are billed generally within a month and payment is generally due within 30 days of billing the customer.

IFRS 15 implementation impact

Prior to January 1, 2018, revenue was recognized to the extent that it was probable that economic benefits would flow to the Partnership for the provision of goods or services and when the revenue could be reliably measured. Revenues were measured at the fair value of the consideration received or to be received, excluding discounts, rebates and sales taxes or duty.

The implementation of IFRS 15 effective January 1, 2018, did not result in any adjustment to the opening balance of retained earnings or to the presentation of the statements of financial position.

The implementation of IFRS 15 had an impact on the accounting policies with respect to contributions from customers and developers. Prior to January 1, 2018 contributions from both customers and developers were initially recorded as deferred revenue when received and were recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which they relate. On implementation of IFRS 15, contributions received from customers where the Partnership has an ongoing performance obligation to the customer are within the scope of IFRS 15. These contributions continue to be presented as deferred revenue when received and subsequently recognized as revenue as described in note 3(h). Contributions from developers are not within the scope of IFRS 15 as they do not give rise to a contract with the customer. Currently there is no specific IFRS guidance on accounting for contributions received from developers. The Partnership has developed an accounting policy for the initial recognition of such contributions and subsequent recognition of the related revenue, as described in note 3(h).

(d) Income taxes

As a limited partnership, ENGLP is not taxed at the entity level under the Canadian Income Tax Act. All income tax consequences of its operations are borne by its Partners on a pro rata basis in proportion to their interest in the Partnership.

(e) Inventories

Small parts and other consumables, the majority of which are consumed by the Partnership in the provision of its goods and services to customers, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances. The Company estimates the value of inventory that is expected to be used in the construction of property, plant and equipment (PP&E) and reports this value as construction work in progress under PP&E.

(f) Property, plant and equipment

PP&E are recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Cost includes contracted services, materials and direct labor costs on qualifying assets. Where parts of an item of PP&E have different estimated economic useful lives, they are accounted for as separate items (major components) of PP&E.

The cost of major inspections and maintenance is recognized in the carrying amount of the item if the asset recognition criteria are satisfied. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing are expensed as incurred.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated economic useful lives of items of each depreciable component of PP&E, from the date they are available for use, as this most closely reflects the expected usage of the assets. Land and construction work in progress are not depreciated. Estimating the appropriate economic useful lives of assets requires judgment and is generally based on estimates of life characteristics of similar assets. The estimated economic useful lives, methods of depreciation and residual values are reviewed annually with any changes adopted on a prospective basis.

The ranges of estimated economic useful lives for PP&E assets used are as follows:

Information systems and other	4 – 52 years
Machinery and equipment	6 – 15 years
Natural Gas distribution	6 – 51 years

Gains or losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(g) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any. The cost of a group of intangible assets acquired in a transaction, including those acquired in a business combination that meet the specified criteria for recognition apart from goodwill, is allocated to the individual assets acquired based on their relative fair value.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials and direct labor costs on qualifying assets.

Other rights represent the costs to acquire Franchise rights. Other rights are recorded at cost at the date of acquisition. Subsequent expenditures are capitalized only when it increases the future economic benefit in the specific asset to which it relates.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated economic useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. The estimated economic useful lives and methods of amortization are reviewed annually with any changes adopted on a prospective basis.

The estimated economic useful lives for intangible assets with finite lives are as follows:

Software	10 years
Other rights	20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are included within depreciation and amortization.

(h) Deferred revenue

Certain assets may be contributed by customers or constructed using non-refundable cash contributions from customers. Non-refundable customer contributions received towards construction or acquisition of an item of PP&E, which are used to provide ongoing goods or services to these customers, are recorded as deferred revenue. The deferred revenue is initially recorded at the fair value of contributed assets, or the amount of cash contributions received, and is recognized as revenue on a straight-line basis over the estimated lives of the contracts with the customers. Where contracts with customers are perpetual and the related contributed asset is used to provide ongoing goods or services to customers, the life of the contract is estimated to be equivalent to the economic useful life of the asset to which the contribution relates.

Certain assets are contributed by developers or acquired or constructed using non-refundable cash contributions from developers. Currently there is no specific IFRS guidance on accounting for contributions received from developers. In accordance with IAS 8, the Partnership has developed an accounting policy for the initial recognition of such contributions and subsequent recognition of the related revenue. These contributions are recorded as deferred revenue, at the fair value of the contributed assets or the amount of cash contribution received, and are recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which the contribution relates.

(i) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation.

(j) Non-derivative financial instruments

Financial assets are identified and classified as measured at amortized cost. Prior to January 1, 2018, financial assets were classified as loans and receivables. Financial liabilities continue to be classified as measured at amortized cost, as there is no change in classification of financial liabilities under IFRS 9.

Financial assets and financial liabilities are presented on a net basis when the Partnership has a legally enforceable right to offset the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

At amortized cost

Cash and trade and other receivables are classified as financial assets measured at amortized cost.

The Partnership's financial assets are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost using the effective interest method less any impairment as described in note 3(k). The effective interest method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

The Partnership's trade and other payables, customer deposits and loans and borrowings are classified as financial liabilities at amortized cost and recognized on the date at which the Partnership becomes a party to the contractual arrangement. Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

Financial liabilities are initially recognized at fair value, plus directly attributable transaction costs, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

The following table summarizes the classification and measurement for each class of the Partnership's financial assets and financial liabilities up to December 31, 2017 and subsequent to adoption of IFRS 9 effective January 1, 2018.

	Up to December 31, 2017	**Effective January 1, 2018**
Measured at amortized cost		
Cash	Loans and receivables	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost
Trade and other payables	Other financial liabilities	Amortized cost
Loans and borrowings	Other financial liabilities	Amortized cost
Customer deposits	Other financial liabilities	Amortized cost

The financial instruments of the Partnership have been disclosed at fair value using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

(k) Impairment of financial assets

The Partnership uses the "expected credit loss" (ECL) model for calculating impairment and recognizes ECL as a loss allowance for financial assets measured at amortized cost.

For trade receivables without significant financing component, the Partnership applies the simplified approach and uses a provision matrix that is based on the Partnership's historical credit loss experience for trade receivable, current market conditions and future expectations, to estimate and recognize the lifetime ECL. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis taking into consideration the unique risk factors associated with each customer group.

Prior to January 1, 2018, the Partnership was using objective evidence as the criteria to recognize impairment losses on financial assets. On implementation of IFRS 9 effective January 1, 2018, the Partnership changed the criteria for recognition of an impairment loss to utilize the ECL model as described above, which resulted in an increase in the lifetime ECL on trade receivables of $13. This has been adjusted in opening balance of retained earnings.

(l) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. 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 the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (CGU). For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amount of the assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(m) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee, the application of which is effective for periods beginning on or after January 1, 2019. The Partnership does not expect any significant impact on its accounting policies on implementation of these new accounting pronouncements.

4. Use of judgments and estimates

The preparation of the Partnership's financial statements in accordance with IFRS requires management to make judgments in the application of account policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in notes:

Note 3(b) - Business combinations and goodwill
Note 3(c) - Revenue recognition
Note 3(i) - Provisions

(b) Estimates

The Partnership reviews its estimates and assumptions on an ongoing basis, uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates.

Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Revenues and natural gas purchases

Accounting estimates were made in determining revenue recognized for unbilled customer consumption which estimates usage using volumes of natural gas entering into the distribution system.

(In thousands of Canadian dollars unless otherwise indicated)

Property, plant and equipment and Intangible assets

Estimating the appropriate economic useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of similar assets.

Fair value measurement

For accounting measures such as determining asset impairments, purchase price allocations for the business combination and recording financial assets and liabilities. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

5. Revenues

	2018	2017
Natural gas sales	$ 6,293	$ 1,408
Provision of services	5,818	1,809
	$ 12,111	$ 3,217

As explained in note 3(c), the Partnership did not have any impacts on the implementation of IFRS 15 on January 1, 2018.

Revenue from contracts with customers expected to be recognized in future periods related to performance obligations that are unsatisfied or partially satisfied at the reporting date are as follows:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Contract liabilities - contributions received from customers and developers[1]	$ 3	$ 3	$ 3	$ 3	$ 3	$ 101	$ 116
Total	$ 3	$ 3	$ 3	$ 3	$ 3	$ 101	$ 116

1 At December 31, 2018, the Company had $116 of deferred revenue recorded in the statements of financial position related to contributions received from customers and developers. Revenue will be recognized in future periods related to this balance, as described in note 3(h), over periods ranging from 38 to 50 years.

The Partnership has numerous contracts with customers for supply of natural gas. These contracts are perpetual with no agreed fixed term and can be terminated at any time either by customer or by the Partnership. Under the terms of the contracts, in case of termination of these contracts, the Partnership has the right to receive payment for the performance completed to the termination date.

6. Depreciation and amortization

	2018	2017
Depreciation of property, plant and equipment	$ 782	$ 174
Amortization of intangible assets	85	16
Gain on disposal of assets	(5)	-
	$ 862	$ 190

(In thousands of Canadian dollars unless otherwise indicated)

7. Trade and other receivables

	2018	2017
Trade receivables	$ 1,235	$ 1,343
Unbilled revenue	795	980
Gross accounts receivable	2,030	2,323
ECL allowance (note 20)	(85)	(102)
Net accounts receivable	$ 1,945	$ 2,221

Details of the aging of accounts receivables and analysis of the changes in the ECL allowance are provided in note 20.

8. Inventories

	2018	2017
Work in progress	$ 13	$ 48
Raw materials	66	34
	$ 79	$ 82

During the year ended December 31, 2018, $72 (2017 - $6) was expensed to other raw materials and operating charges.

No significant inventory write-downs were recognized in the year ended December 31, 2018 or 2017. No significant reversals of previous write-downs were recorded in the years ended December 31, 2018 or 2017.

At December 31, 2018 or 2017, no inventories were pledged as security for liabilities.

(In thousands of Canadian dollars unless otherwise indicated)

9. Property, plant and equipment

	Land	Information systems & other	Construction work in progress	Machinery & equipment	Natural gas distribution	Total
Cost						
Balance, beginning of 2018	$ 42	$ 529	$ 345	$ 101	$ 17,014	$ 18,031
Additions	-	-	2,412	-	-	2,412
Transfers into service	-	-	(2,231)	148	2,083	-
Disposals and retirements	-	-	-	-	(1)	(1)
Balance, end of 2018	42	529	526	249	19,096	20,442
Accumulated depreciation						
Balance, beginning of 2018	-	24	-	2	148	174
Depreciation	-	54	-	29	698	781
Balance, end of 2018	-	78	-	31	846	955
Net book value, end of 2018	$ 42	$ 451	$ 526	$ 218	$ 18,250	$ 19,487

	Land	Information systems & other	Construction work in progress	Machinery & equipment	Natural gas distribution	Total
Cost						
Additions through business acquisition	$ 42	$ 353	$ -	$ 101	$ 16,989	$ 17,485
Additions	-	176	345	-	25	546
Balance, end of 2017	42	529	345	101	17,014	18,031
Accumulated depreciation						
Depreciation	-	24	-	2	148	174
Balance, end of 2017	-	24	-	2	148	174
Net book value, end of 2017	$ 42	$ 505	$ 345	$ 99	$ 16,866	$ 17,857

There are no security charges over the Partnership 's property, plant and equipment.

(In thousands of Canadian dollars unless otherwise indicated)

10. Intangible assets and goodwill

	Goodwill	Software	Other rights	Total
Cost				
Balance, beginning of 2018	$ 1,886	$ 42	$ 1,181	$ 3,109
Business acquisition adjustment (Note 23)	(78)	-	-	(78)
Investment in intangible assets	-	-	21	21
Balance, end of 2018	1,808	42	1,202	3,052
Accumulated amortization				
Balance, beginning of 2018	-	2	14	16
Amortization	-	4	81	85
Balance, end of 2018	-	6	95	101
Net book value, end of 2018	$ 1,808	$ 36	$ 1,107	$ 2,951

	Goodwill	Software	Other rights	Total
Cost				
Additions through business acquisition	$ 1,886	$ 1	$ 1,181	$ 3,068
Investment in intangible assets	-	41	-	41
Balance, end of 2017	1,886	42	1,181	3,109
Accumulated amortization				
Amortization	-	2	14	16
Balance, end of 2017	-	2	14	16
Net book value, end of 2017	$ 1,886	$ 40	$ 1,167	$ 3,093

There are no security charges over the Partnership's intangible assets.

For purposes of impairment testing, goodwill acquired through business combination has been allocated to a single CGU. The most recent review of goodwill was performed in the fourth quarter. Management reviewed conditions since the last review was performed and determined that no circumstances occurred since then to require a revision to the assumptions used in the value in use calculations.

The recoverable amount of the CGU was determined using a discounted cash flow analysis. Forecasted cash flows reflect revenues consistent with OEB methodology of allowing a fair return on prudently placed capital that is recoverable through customer rates. Operating costs reflect historical costs of running the business, adjusted for inflation, and capital spending forecasts reflect system integrity and capacity needs of utility infrastructure. The pre-tax discount rate applied to cash flow projections was 5.0% (2017 – 5.1%).

Key assumptions used in value-in-use calculations

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing natural gas supply in a rate-regulated environment. In the case of CGUs operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator's approved weighted average cost of capital for the underlying utility.

The calculation of value in use for the CGUs is most sensitive to the following assumptions:

Discount rates

The discount rates used were estimated based on the weighted average cost of capital for the CGU, which, in the case of rate-regulated businesses, are the approved rate of return on capital allowed by the regulator. These rates were further adjusted to reflect the market assessment of any risk specific to the cash-generating unit for which future estimates of cash flows have not been adjusted.

(In thousands of Canadian dollars unless otherwise indicated)

Timing of future rate increases

Revenue growth is forecast to continue in concordance with rate base growth. Prudent capital investment in utility infrastructure, to meet customer demand and system integrity needs, may be included in rate base and allowed to earn a fair return by the regulator. Such return on rate base is recovered through customer rates which drive revenue. In the case of rate-regulated businesses, if future rate filings are delayed then rate increases and increased cash flows from revenues would be affected.

Sensitivity to changes in assumptions

Assumptions have been tested using reasonably possible alternative scenarios. For all scenarios considered, the recoverable value remained above the carrying amount of the CGU.

11. Trade and other payables

	2018	2017
Trade payables	$ 468	$ 260
Accrued liabilities	2,092	853
Accrued interest	30	30
	$ 2,590	$ 1,143

12. Loans and borrowings

	2018	2017
Short-term note payable to EPCOR[1]	$ 1,055	$ 3,153
Long-term note payable to EPCOR[2]		
At 3.83%, due in 2047	8,660	8,660
Total loans and borrowings	9,715	11,813
Less: current portion	1,055	3,153
	$ 8,660	$ 8,660

1 Short-term note payable to EPCOR is unsecured and due on demand. Interest is payable monthly.

2 The long-term notes payable to EPCOR are unsecured. Interest on notes is payable semi-annually while principal is due at the end of the term.

13. Deferred revenue

	2018	2017
Balance, beginning of year	$ 13	$ -
Contributions received	104	13
Revenue recognized	(1)	-
	116	13
Less: current portion	3	-
Balance, end of year	$ 113	$ 13

Contributions received include cash contributions of $104 (2017 – $13).

14. Provisions

Provisions consist of employee benefits obligations for benefits provided under employee incentive plans.

(In thousands of Canadian dollars unless otherwise indicated)

		2018		2017
Balance, beginning of year	$	19	$	-
Provisions through business acquisition		-		3
Provisions made during the year		50		16
Provisions utilized during the year		(5)		-
Balance, end of year	$	64	$	19

All employee benefit provision balances are expected to be utilized within one year.

15. Partnership units

The Partnership is authorized to issue unlimited number of Class A common units without nominal or par value. The units are voting and participate equally in profits, losses and capital distributions of the Partnership.

On November 4, 2016, 1,000 partnership units were issued. The General Partner was issued one unit and the Limited Partner 999 units.

On November 1, 2017, 13,358,556 additional units were issued. The General Partner was allocated an additional 13,359 units and the Limited Partner an additional 13,345,197 units.

The General Partner holds 13,360 (2017 – 13,360) Class A common units having capital contribution of $14 in the Partnership. It manages the operations of the Partnership and has a 0.10% (2017 – 0.10%) interest in the profits, losses and capital distributions of the Partnership.

The Limited Partner holds 13,346,196 (2017 – 13,346,196) Class A common units representing a net capital contribution of $13,346 (2017 - $13,346) in the Partnership. The Limited Partner has 99.90% (2017 – 99.90%) interest in the profits, losses and capital distributions of the Partnership.

16. Changes in non-cash working capital

		2018		2017
Trade and other receivables (note 7)	$	276	$	(2,221)
Inventories (note 8)		3		(82)
Prepaid expenses		270		(358)
Trade and other payables (note 11)		1,447		1,143
Customer deposits		(25)		103
	$	1,971	$	(1,415)
Included in specific items on statements of cash flows:				
Business acquisition		-		1,469
Adjustment to opening trade receivables on implementation of IFRS 9 (note 3(k))		13		-
Changes in non-cash operating working capital	$	1,984	$	54

17. Changes in liabilities arising from financing activities:

		Short-term loans and borrowings		Long-term loans and borrowings
Balance, beginning of year	$	3,153	$	8,660
Issued		46,509	$	-
Redemptions or repayments		(48,607)		-
Balance, end of year	$	1,055	$	8,660

18. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR, which is in turn 100% owned by The City of Edmonton. The

(In thousands of Canadian dollars unless otherwise indicated)

Partnership purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, and information technology services pursuant to service agreements. Transactions between the Partnership and its related parties are in the normal course of operations, and are generally based on normal commercial rates, or as agreed to by the parties.

The following summarizes the Partnership's related party transactions with EPCOR and its subsidiaries:

	2018	2017
Statements of Comprehensive Income		
Other administrative expenses (a)	$ 1,008	$ 1,124
Finance expenses (b)	332	22

(a) Relates to expenditures for administrative services.

(b) Relates to interest expense on short-term and long-term notes payable to EPCOR.

The following summarizes the Partnership's related party balances with EPCOR and its subsidiaries:

	2018	2017
Statements of Financial Position		
Property, plant and equipment (c)	$ 1	$ -
Trade and other payables (d)	172	30
Loans and borrowings (e)	9,715	11,813
Provisions (f)	64	8

(c) Relates to expenditures for information services projects.

(d) Relates to balances payable for administration of services and accrued interest on long-term notes payable to EPCOR.

(e) Relates to short-term and long-term notes payable to EPCOR.

(f) Relates to provisions for employee benefits.

19. Financial instruments

Fair value

The carrying amounts of cash, trade and other receivables, customer deposits and trade and other payables approximate their fair values due to the short-term nature of these financial instruments.

The carrying amount and fair value of the Partnerships remaining financial instrument are as follows:

	2018		2017	
	Carrying amount	Fair value	Carrying amount	Fair value
Loans and borrowings (note 12)	$ 9,715	$ 9,221	$ 11,813	$ 11,813

Loans and borrowings

Short-term loans and borrowings are measured at amortized cost and their carrying value approximate their fair value due to its short-term nature of these financial instruments.

The fair value of the Partnership's long-term loans and borrowings is based on determining a current yield for the Partnership's debt at December 31, 2018 and 2017. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Partnership's debt.

20. Financial risk management

Overview

The Partnership is exposed to a number of different financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Partnership's overall risk management process is designed to identify, assess, measure, manage, mitigate and report on business risk which includes financial risk. Enterprise risk management is overseen by Board of Directors of EPCOR and senior management is responsible for fulfilling objectives, targets, and policies approved by the Board of Directors of EPCOR. EPCOR's Director, Audit and Risk Management provide the Board of Directors of EPCOR with an enterprise risk assessment quarterly. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the EPCOR's business objectives and risk tolerance. The Partnership's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Financial risk management including interest rate risk, liquidity risk and the associated credit risk management is carried out by EPCOR's centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors of EPCOR, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as energy prices and interest rates. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Partnership's financial assets and liabilities held. EPCOR's financial exposure management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the interest rate risk throughout the Partnership.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Interest rate risk associated with short-term loans and borrowings is immaterial due to its short-term maturity. At December 31, 2018 and 2017, all long-term loans and borrowings was fixed rate.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's credit risk management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the group including the Partnership. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis. To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as master netting agreements, pre-payment arrangements and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

Maximum credit risk exposure

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $1,945 (2017 - $2,221) (note 7). These carrying amounts do not take into account collateral held. At December 31, 2018, the Partnership held cash deposits and a letter credit of $310 (2017 - $336) as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with natural gas services to customers. The Partnership's trade receivables are unrated, unsecured and not of investment grade.

(In thousands of Canadian dollars unless otherwise indicated)

Rate-regulated customer credit risk

Credit risk exposure is generally limited to amounts due from residential and commercial customers for natural gas consumed but not yet paid for. The Partnership mitigates credit risk from counterparties by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits.

Trade and other receivables and ECL allowance

Trade and other receivables consist primarily of amounts due from retail customers including residential and commercial customers. The Partnership mitigates these exposures by dealing with creditworthy counterparties and, when appropriate and contractually allowed, obtaining appropriate security from customers.

For retail customers, represented by a diversified customer base, credit losses are generally low and the Partnership provides an allowance for lifetime ECL.

The Partnership calculates the ECL allowance on accounts receivable using a provision matrix approach, which is based on the Partnership's historical credit loss experience and current economic conditions (including forward-looking information) for accounts receivables to estimate the lifetime ECL allowance. The provision matrix specifies fixed provision rates depending on the number of days that a trade receivable is due or past due. The total lifetime ECL allowance at December 31, 2018 is $85 (2017 - $102).

The gross amount of trade receivables and corresponding ECL is as follows:

December 31, 2018		Gross trade receivables		Expected credit loss allowance		Net trade receivables
Current (a)	$	1,861	$	6	$	1,855
Outstanding 31 to 60 days		58		2		56
Outstanding 61 to 90 days		17		1		16
Outstanding more than 90 days		94		76		18
	$	2,030	$	85	$	1,945

December 31, 2017		Gross trade receivables		Allowance for doubtful accounts		Net trade receivables
Current (a)	$	2,169	$	-	$	2,169
Outstanding 31 to 60 days		57		-		57
Outstanding 61 to 90 days		(5)		-		(5)
Outstanding more than 90 days		102		102		-
	$	2,323	$	102	$	2,221

(a) Current amounts represent trade and other receivables as well as accrued revenues outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

The change in the ECL allowance was as follows:

		2018		2017
Balance, beginning of year	$	102	$	-
Adjustment on implementation of IFRS 9 (note 3(k))		(13)		
		89		-
Allowance acquired through business acquisition		-		96
Additional allowances created		(4)		6
Balance, end of year	$	85	$	102

(In thousands of Canadian dollars unless otherwise indicated)

During the year, the Partnership recognized $(4) (2017 - $6) ECL as expense in profit or loss account relating to customer amounts that the Partnership determined may not be fully collectable. The lifetime ECL allowance is determined by considering the unique factors of different customer types. Write-offs are determined either by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related ECL allowance is recorded when the Partnership has determined that recovery is not possible.

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they become due. The Partnership's liquidity is managed centrally by EPCOR's Treasury function. EPCOR manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements of the Partnership are addressed through operating cash flows, and if necessary, intercompany financing from EPCOR.

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments, are as follows:

At December 31, 2018	2019	2020	2021	2022	2023	2024 and thereafter	Total contractual cash flows
Trade and other payables[a]	$ 2,560	$ -	$ -	$ -	$ -	$ -	$ 2,560
Customer Deposits	78	-	-	-	-	-	78
Loans and borrowings	1,055	-	-	-	-	8,660	9,715
Interest payments on loans and borrowings	332	332	332	332	332	7,959	9,619
	$ 4,025	$ 332	$ 332	$ 332	$ 332	$ 16,619	$ 21,972

At December 31, 2017	2018	2019	2020	2021	2022	2023 and thereafter	Total contractual cash flows
Trade and other payables[a]	$ 1,113	$ -	$ -	$ -	$ -	$ -	$ 1,113
Customer Deposits	103	-	-	-	-	-	103
Loans and borrowings	3,153	-	-	-	-	8,660	11,813
Interest payments on loans and borrowings	332	332	332	332	332	8,290	9,950
	$ 4,701	$ 332	$ 332	$ 332	$ 332	$ 16,950	$ 22,979

(a) Excluding accrued interest on loans and borrowings of $30 (2017 - $30).

The Partnership's undiscounted cash flow requirements and contractual maturities in the next twelve months of $4,025 (2017 - $4,701) will be funded from operating cash flows and additional loans and borrowings.

21. Capital management

The Partnership's primary objectives when managing capital is to safeguard the Partnership's ability to continue as a going concern and pay cash distributions to its unit holders. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions.

(In thousands of Canadian dollars unless otherwise indicated)

The Partnership manages capital through regular monitoring of cash requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Partnership matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Partnership considers its capital structure to consist of loans and borrowings (including current portion) net of cash and unit holder's equity. The following table represents the Partnership's total capital:

	2018	2017
Loans and borrowings (including current portion) (note 12)	$ 9,715	$ 11,813
Cash	(1,095)	(2,408)
Net debt	8,620	9,405
Total equity	13,082	12,928
Total capital	$ 21,702	$ 22,333

To manage or adjust its capital structure, the Partnership can issue new debt, repay existing debt or issue or redeem common units.

22. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements as at December 31, 2018:

(a) Commitments for the minimum cost of the monthly demand charge from Union Gas regardless of the total volume of gas delivered into the distribution system estimated at $1,216 (2017 - $900) annually.

(b) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $663 (2017 - $320) annually. These estimates are subject to change based on actual activity levels.

23. Business acquisition

Effective November 1, 2017, the Partnership assumed operations and acquired substantially all of the net natural gas distribution assets of Natural Resource Gas Limited ("NRG") for cash consideration of $22,019. NRG provides services to approximately 8,700 customers located in several Southern Ontario municipalities. Prior to the acquisition of NRG net assets, there was no operating activity in the Partnership.

During 2018, the Partnership adjusted the Business acquisition for updated closing balances which had the impact of reducing Goodwill and cash consideration by $78 to $21,941.

The fair values of net assets acquired in the acquisition of NRG are as follows:

Fair value of net assets acquired:	
Trade and other receivables	$ 1,022
Inventories	112
Prepaid expenses	478
Property, plant and equipment	17,485
Intangible assets	1,182
Goodwill	1,808
Other liabilities	(146)
Net assets	$ 21,941

The property, plant and equipment primarily consist of natural gas distribution assets.

The intangible assets consist of the right to distribute natural gas within the franchise area of southern Ontario for a period of 20 years.

The goodwill recognized at fair value of $1,808 includes the value of the expected benefits to the Partnership by providing entry into the Ontario natural gas and utility market, along with the potential for expanded operations in the Ontario region.

The Partnership incurred integration costs of $1,000 to complete the acquisition. Integration costs are included on the 'Other administration expenses' financial statement caption in 2017.

For the period ending December 31, 2018	IFRS Balance Sheet	Regulatory Adjustments	Regulatory Balance Sheet
ASSETS			
Current assets			
Cash and cash equivalents	1,095,156	0	1,095,156
Trade and other receivables	1,945,115	297,452	2,242,568
Prepaid expenses	87,743	0	87,743
Derivative financial instruments asset	0	0	0
Inventories	79,044	0	79,044
	---------------	---------------	---------------
Total current assets	3,207,058	297,452	3,504,510
	---------------	---------------	---------------
Non-current assets			
Other assets	0	0	0
Derivative financial instruments asset	0	0	0
Finance lease receivables	0	0	0
Other financial assets	0	0	0
Deferred tax assets	0	0	0
Investment in associates	0	0	0
Intangible assets	1,142,825	-530,635	612,190
Property, plant and equipment	19,486,441	-5,643,749	13,842,692
Goodwill	1,808,330	-1,808,330	0
	---------------	---------------	---------------
Total non-current assets	22,437,595	-7,982,714	14,454,882
	---------------	---------------	---------------
TOTAL ASSETS	25,644,653	-7,685,262	17,959,392
	===============	===============	===============

For the period ending December 31, 2018	IFRS Balance Sheet	Regulatory Adjustments	Regulatory Balance Sheet
LIABILITIES AND EQUITY			
Current liabilities			
Trade and other payables	2,590,582	0	2,590,582
Income tax payable	0	0	0
Derivative financial instrument liabilities	0	0	0
Loans and borrowings	1,054,688	-242,607	812,081
Advances for construction	0	0	0
Deferred revenue	2,565	0	2,565
Provision	64,558	0	64,558
Other current liabilities/Customer Deposits	77,722	0	77,722
	--------------	--------------	--------------
Total current liabilities	3,790,114	-242,607	3,547,508
	--------------	--------------	--------------
Non-current liabilities			
Derivative financial instruments liabilities	0	0	0
Loans and borrowings	8,660,000	0	8,660,000
Advances for construction	0	0	0
Deferred revenues	113,376	-614	112,762
Deferred tax liabilities	0	0	0
Provisions	0	0	0
Other liabilities	0	0	0
	--------------	--------------	--------------
Total non-current liabilities	8,773,376	-614	8,772,762
	--------------	--------------	--------------
Total liabilities	12,563,490	-243,220	12,320,271
	--------------	--------------	--------------
Equity			
Share capital	13,359,556	-7,748,872	5,610,684
Retained earnings	-278,393	306,830	28,437
Accumulated OCI	0	0	0
Non-controlling interests	0	0	0
	--------------	--------------	--------------
Total equity	13,081,163	-7,442,041	5,639,122
	--------------	--------------	--------------
TOTAL LIABILITIES AND EQUITY	25,644,653	-7,685,262	17,959,392
	==============	==============	==============

For the period ending December 31, 2018	**IFRS Income Statement**	**Regulatory Adjustments**	**Regulatory Income Statement**
Energy Sales	6,293,463	-1,980,235	4,313,228
Water Sales	0	0	0
Wastewater Service	0	0	0
Commercial Services	5,684,783	1,793,843	7,478,626
Contributions and Grants	1,450	-333	1,117
Other Revenue	130,686	0	130,686
Finance Lease Income	0	0	0
Construction Revenue	0	0	0
Interest Income	630	0	630
	---------------	---------------	---------------
Revenues	12,111,013	-186,725	11,924,288
	---------------	---------------	---------------
Energy Purchases and System Access Fees	4,483,248	0	4,483,248
Other Raw Materials and Operating Charges	1,540,919	0	1,540,919
Staff Costs and Employee Benefits Expense	1,238,524	0	1,238,524
Depreciation and Amortization Expense	861,753	295,002	1,156,755
Other Administrative Expenses	2,917,643	-608,668	2,308,975
Franchise Fees & Property Taxes	573,251	0	573,251
	---------------	---------------	---------------
Expenses	11,615,338	-313,666	11,301,673
	---------------	---------------	---------------
Operating income	495,675	126,941	622,615
Net Finance Expense	-354,328	-8,682	-363,010
Share of (Profit) Loss of an Associate	0	0	0
Impairment - Investment	0	0	0
(Loss)/Gain on Disposition of Investments	0	0	0
	---------------	---------------	---------------
(Loss)/income before tax	141,346	118,259	259,605
	---------------	---------------	---------------
Income Taxes	0	0	0
Current	0	0	0
Deferred	0	0	0
	---------------	---------------	---------------
(Loss)/profit for the year	141,346	118,259	259,605
	===============	===============	===============
Net Income Check	141,346	118,259	259,605
	===============	===============	===============

1-STAFF-7

Reference: **Exhibit 1/ Tab1/ Schedule 1/ Pg. 62**
Exhibit 1/ Tab 2/ Schedule 5/ Sept. 2017 Audited Financial Statements

Request:

EPCOR changed its tax status on November 1, 2017 from a corporation to a limited partnership.

(a) Please discuss any tax impacts this has had, including whether there were any tax savings/costs and tax assets/liabilities generated.

(b) Please discuss whether the change in tax status has any impacts to EPCOR's rates.

(c) Per Note 14 of the Sept. 2017 financial statements, in prior years, there was a capital tax loss of $2.6M that was carried forward and available for future use against capital gains. In 2017, there was a future tax asset of $1.2M. Please explain how the capital tax loss and tax asset has been treated since 2017.

(d) Please explain how assets were valued upon acquisition from NRG. If the assets were valued at fair value, please explain the tax impact (e.g. on CCA).

Response:

(a) To clarify, EPCOR did not change its tax status from a Corporation to a Limited Partnership on November 1, 2017. On November 1, 2017 EPCOR, a limited partnership, acquired the business and assets of the Aylmer operations from NRG, the previous owner of the business and assets of the Aylmer operations.

The reference in paragraph 134 of Exhibit 1, Tab 1, Schedule 1, page 62 is to the tax status of the Aylmer utility operations, which were held in a limited partnership as of November 1, 2017. There were no tax savings/costs nor tax assets/liabilities generated as a result of the limited partnership acquiring the business and assets of the Aylmer operations, except that any income tax owing related to the Aylmer operations will be borne by the partners of the limited partnership as opposed to the limited partnership itself.

(b) The change in Aylmer utility operations tax status would have no impact on EPCOR's rates.

(c) The $2.6M capital tax loss relates to the sale of the former water heater business by Natural Resources Gas Limited. The future tax asset is related to this capital tax loss carry-forward balance. As the water heater business was separate from the Aylmer utility operations, these balances do not have any impact and have not been considered for this rate filing.

(d) Identifiable assets acquired and liabilities assumed are measured initially at their fair values at the date of acquisition. None of the fair value differences related to acquisition of the assets of the Aylmer operations have been included in rate base and as such their impacts are not included in the calculation of the Aylmer operation's revenue requirement in the Application.

The CCA calculations presented in Table 4.5.2-1 (Exhibit 4, Tab 1, Schedule 1, page 67) inadvertently included an increase to the UCC balances to fair value. The fair value adjustments are not included in rate base for revenue requirement calculation purposes and as such, the UCC balances should also exclude these amounts for regulatory income tax expense calculation purposes. The CCA calculation has been amended and the impact of the adjustment is shown in response to 9-STAFF-78.

1-STAFF-8

Reference: **Exhibit 1/ Tab 2/ Schedule 2/ Dec. 2017 Audited Financial Statements**

Request:

Note 11 of the 2017 audited financial statements show short-term notes payable to EPCOR of $3.153 million that is due on demand.

(a) Please explain whether there has been any indication of when the notes payable are due.

(b) If EPCOR Inc. were to recall the notes payable, please explain how EPCOR will be able to fund the repayment and whether it will pose any issues on its cash flows and financial viability.

Response:

(a) The short-term notes are due on demand with a term of 1 month. The notes are re-issued on a monthly basis, to the extent that EPCOR requires short term borrowing. The balance represents cash payments made to EPCOR's vendors and other parties in the normal course of operations.

(b) EPCOR Utilities Inc. provides short-term borrowing to all of its subsidiaries. If the amount was recalled, EPCOR would have to use Cash on hand and third-party financial institution(s) for future periodic short-term borrowing. This would have no impact on EPCOR's cash flows or financial viability as a third-party provider would replace EPCOR Utilities Inc. as the short-term lender.

1-STAFF-9

Reference: **Exhibit 1/ Tab 2/ Schedule 7/ Pgs. 1-12**
Exhibit 2/ Tab 1/ Schedule 1/ Pg. 6 - Table 2.2.1-3

Request:

Regarding the reconciliation between audited financial statements and regulatory financial statements:

(a) Please provide an explanation for each adjusting item in the 2015, 2016, 2017 and 2017 stub period reconciliation.

(b) In Table 2.2.1-3, the closing net asset value for the 2017 stub period is $13,079k. In the reconciliation between audited and regulatory financial statements for the 2017 stub period, regulatory intangible assets and PP&E total $13,423k. There is a difference of $344,000. Please explain the difference and make any changes as necessary.

Response:

(a) See 1-STAFF-9 Attachment 1.

(b) The regulatory financial statements for the 2017 stub period includes $344,000 of Construction Work in Progress that was inadvertently classified as PP&E (USoA #100 instead of USoA #115).

Income Statement	Regulatory Adjustments[a]					
	2015	Tickmark	2016	Tickmark	31-Oct 2017	Tickmark
Gas commodity revenue	$ -		$ -		$ -	
Gas commodity cost	-		-		-	
Gross margin on commodity	-		-		-	
Distribution revenue	-		-		-	
Distribution costs	-		-		-	
Gross margin on distribution	-		-		-	
Other sales	-		-		-	
Labour and Materials costs related to other sales	-		-		-	
Gross margin on other sales	-		-		-	
TOTAL GROSS MARGIN	-		-		-	
OPERATING EXPENSES	-		-		-	
INCOME FROM OPERATIONS	-		-		-	
OTHER INCOME (EXPENSES)	-		-		-	
Other revenue	-		-		-	
Over Expense prior years distribution costs	-		-		-	
Interest income on investments	-		-		-	
Losses on disposal of property, plant and equipment	-		-		-	
Losses on disposal of investments	-		-		-	
	-		-		-	
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	-		-		-	
INCOME TAX RECOVERY	-		-		-	
Current income taxes	136,000	b	-		-	
Future income taxes	-		-		-	
	136,000		-		-	
INCOME (LOSS) FROM CONTINUING OPERATIONS	(136,000)		-		-	
Gain on Disposal of discontinued operations	-		-		-	
Income related to discontinued operations	161,000	b	-		-	
TOTAL INCOME FROM DISCONTINUED OPERATIONS	161,000		-		-	
NET INCOME FOR THE YEAR	$ 25,000		$ -		$ -	

a - The 2015 to October 31, 2017 NRG Regulatory financial statement adjustments are documented above. We don't have enough information related to these periods to determine the rationale for these adjustments with certainty; however, we have provided a rationale for some of the change where appropriate.

b - Based on the NRG 2015 audited financial statements, NRG had sold its water heater and rental division assets. The regulatory adjustments likely relate to the sale.

Balance Sheet	**Regulatory Adjustments**[a]					
	2015	Tickmark	2016	Tickmark	31-Oct 2017	Tickmark
ASSETS						
CURRENT						
Accounts receivable	$ -		$ -		$ 852,229	c
Inventory	-		-		111,569	c
Income taxes recoverable	-		-		-	
Future Income taxes	-		-		-	
Prepaid expenses	-		-		25,546	c
Assets held for sale	-		-		(14,745,363)	c
Assets relating to discontinued operations	-		-		-	
	-		-		-	
			-		(13,756,019)	
			-		-	
Property, plant and equipment	-		-		12,606,528	
Other assets:						
Franchises and consents	-		-		441,430	c
Deferred Charges	1,682,643	b	-		662,105	c
Future Income taxes	-		-		-	
			-		-	
	1,682,643		-		1,103,535	
	$ 1,682,643		$ -		$ (45,956)	
LIABILITIES AND SHAREHOLDERS' DEFICIENCY						
CURRENT						
Bank indebtedness	$ -		$ -		$ -	
Accounts payable and accrued liabilities	1,804,045	b	-		327,208	c
Income taxes payable	(25,000)	b	-		-	
Future income taxes payable	-		-		-	
Deferred revenue	(121,402)	b	-		-	
Customer deposits	-		-		115,901	c
Liabilities transferred with assets held for sale	-		-		(489,065)	c
Term note payable	-		-		-	
	1,657,643		-		(45,956)	
Accounts payable due beyond one year	-		-		-	
	1,657,643		-		(45,956)	
SHAREHOLDERS' EQUITY						
Share capital	-		-		-	
Deficit	25,000	b	-		-	
	-		-		-	
	25,000		-		-	
	-		-		-	
	$ 1,682,643		$ -		$ (45,956)	

a - The 2015 to October 31, 2017 NRG Regulatory financial statement adjustments are documented above. We don't have enough information related to these periods to determine the rationale for these adjustments with certainty; however, we have provided a rationale for some of the change where appropriate.

b - Based on the NRG 2015 audited financial statements, NRG had sold its water heater and rental division assets. The regulatory adjustments likely relate to the sale.

c - Based on the NRG 2017 audited financial statements, NGR had sold its Alymer operations assets. The regulatory adjustments likely relate to the sale.

Income Statement	DEC-17 Regulatory Adjustments	Tickmark
Energy Sales	-31,255	d
Water Sales	0	
Wastewater Service	0	
Commercial Services	-156,719	d
Contributions and Grants	0	
Other Revenue	0	
Finance Lease Income	0	
Construction Revenue	0	
Interest Income	0	

Revenues	-187,974	

Energy Purchases and System Access Fees	0	
Other Raw Materials and Operating Charges	0	
Staff Costs and Employee Benefits Expense	0	
Depreciation and Amortization Expense	-10,818	e
Other Administrative Expenses	-371,211	d
Franchise Fees & Property Taxes	0	

Expenses	-382,028	

Operating income	194,054	
Net Finance Expense	415	d
Share of (Profit) Loss of an Associate	0	
Impairment - Investment	0	
(Loss)/Gain on Disposition of Investments	0	

(Loss)/income before tax	194,469	

Income Taxes	0	
current		
deferred		

(Loss)/profit for the year	194,469	
	==============	
Net Income Check	194,469	
	==============	

d - These regulatory accounting adjustments relate to revenues and expenses that are recorded to the regulatory deferral accounts balances.

e - This regulatory accounting adjustment relates to net differences in depreciation and amortization amounts recorded in ENGLP's International Financial Reporting Standards financial statements versus the regulatory statements. The differences occur as ENGLP's International Financial Reporting Standard financial statements included a step-up to fair value of the Alymer assets acquired by ENGLP. None of these increases are include in the regulated statements.

Balance Sheet	DEC-17 Regulatory Adjustments	Tickmark
ASSETS		
Current assets		
Cash and cash equivalents	0	
Trade and other receivables	-116,141	d
Prepaid expenses	0	
Derivative financial instruments asset	0	
Inventories	0	

Total current assets	-116,141	

Non-current assets		
Other assets	0	
Derivative financial instruments asset	0	
Finance lease receivables	0	
Other financial assets	0	
Deferred tax assets	0	
Investment in associates	0	
Intangible assets	-361,513	f
Property, plant and equipment	-5,279,451	f
Goodwill	5,951,574	f

Total non-current assets	310,610	

TOTAL ASSETS	194,469	
	==============	

d - These regulatory accounting adjustments relate to the re-class of revenues and expenses to the deferral accounts as well as the recording of the regulatory deferral balances which are not included in ENGLP's International Financial Reporting Standards financial statements.

f - Please refer to our response to 1-Staff-10 for details on these differences.

Balance Sheet	DEC-17 0	Tickmark
LIABILITIES AND EQUITY		
Current liabilities		
Trade and other payables	0	
Income tax payable	0	
Derivative financial instrument liabilities	0	
Loans and borrowings	0	
Advances for construction	0	
Deferred revenue	0	
Provision	0	
Other current liabilities/Customer Deposits	0	

Total current liabilities	0	

Non-current liabilities		
Derivative financial instruments liabilities	0	
Loans and borrowings	0	
Advances for construction	0	
Deferred revenues	0	
Deferred tax liabilities	0	
Provisions	0	
Other liabilities	0	

Total non-current liabilities	0	

Total liabilities	0	

Equity		
Share capital	0	
Retained earnings	194,469	g
Accumulated OCI	0	
Non-controlling interests	0	

Total equity	194,469	

TOTAL LIABILITIES AND EQUITY	194,469	
	==============	

g - Income statement impact of regulatory adjusmentments closed out to retained earnings.

1-STAFF-10

Reference: **Exhibit 1/ Tab 2/ Schedule 2/Dec. 2017 Audited Financial Statements**
Exhibit 1/ Tab 2/ Schedule 4/Sept. 2016 Audited Financial Statements
Exhibit 1/ Tab 2/ Schedule 5/Sept. 2017 Audited Financial Statements
Exhibit 1/ Tab 2/ Schedule 7/page 2 - Reconciliation Ending 2017 Stub Period

Request:

Net book value of PP&E and intangibles from the audited financial statements are as follows:

	Sept. 2015	**Sept. 2016**	**Sept. 2017**	**Dec. 2017**
Net book value	$11,405k	$13,147k	$13,048k	$19,064k
Source	2016 statements – PP&E plus franchises and consents	2016 statements - PP&E plus franchises and consents	Sept. 2017 statements note 3 - PP&E plus franchises and consents	Dec. 2017 statements notes 8 and 9 – PP&E plus intangibles excluding goodwill

(a) The net book value has been relatively consistent prior to EPCOR's acquisition of the assets on November 1, 2017. Please explain the increase in fixed assets from September 2017 to December 2017.

(b) In the 2017 stub period reconciliation between financial and regulatory financial statements, there was an adjustment to reallocate amounts between PP&E, intangible assets and goodwill in deriving the regulatory balances. There was also a $311,000 increase to these assets in deriving regulatory balances.

(i) Please explain the reason for the reallocation between assets and how much was reallocated between each of the asset categories.
(ii) Please explain the net increase of $311,000 to these assets.

Response:

(a) The increase in the net book value of PP&E and Intangibles relates to ENGLP acquiring the business and assets of the Aylmer operations from NRG on November 1, 2017. Under International Financial Reporting Standards the PP&E and intangibles were recorded at fair market value on the acquisition date. The fair value of the acquired assets was greater than the book value on the date of acquisition. None of these increases have been included in rate base for ENGLP's Aylmer operations.

(b) (i) The reallocation between assets categories was done to reverse the impact of the fair value step up on the acquisition of the Aylmer operation assets by ENGLP. The impact of the re-class of the fair value adjustments is provided in the table below:

Table 1-STAFF-10-1
Impact of the Re-class of the Fair Value Adjustments
Stub Period Ending December 31, 2017
($)

	Balance Sheet Category	A **IFRS Balance Sheet**	B **Re-class Fair Value Adjustments**	C **Other Regulatory Adjustments**	D **Regulatory Balance Sheet**
1	Intangible Assets	1,206,999	(361,513)		845,486
2	Property, Plant and Equipment	17,857,068	(5,290,268)	10,818	12,577,617
3	Goodwill	1,886,374	5,651,782	299,792	7,837,948
4	**Total**	**20,950,441**	**-**	**310,610**	**21,261,051**

(ii) The $311,000 increase to PP&E and Intangibles is reflected in column C of Table 1-STAFF-10-1, above. The $299,792 adjustment relates to recording the regulatory deferral balances which are not included in ENGLP's IFRS financial statements. The $10,818 increase was the result of an increase in the net book value of PP&E due to a reduction of depreciation from the IFRS statements to the Regulatory statements.

1-STAFF-11

Reference: **SNC-Lavlin System Integrity Study**
Exhibit 1 / Tab 4 / Schedule 2 and EB-2016-0236, Exhibit 2 / Tab 1 / Schedule 1 / Pg. 2 / Lines 1-9

Request:

Natural Resource Gas Limited (NRG) completed a system integrity study in 2016 to assess the NRG distribution system and recommend solutions to resolve system integrity issues affecting the southern area of the NRG distribution system. In response NRG had indicated in its cost of service application (EB-2016-0236) that it intends to implement certain projects including updating the Union Gas Bradley Station, a pipeline from the existing Putnam Station to the northeast region and a second pipeline from the Bradley Station to the Wilson Line.

(a) Please provide information on the capital projects (including amounts spent) completed by NRG to address system integrity issues.

(b) What amounts will be added to the rate base in 2020 with respect to the capital projects referred to in (a)?

(c) The Gas Supply Plan of EPCOR (Exhibit 4, Tab 4, Schedule 1, pg.3) states that a System Integrity Study was completed in 2015 by NRG and SNC-Lavlin. The study recommended the addition of a number of pipelines for system reinforcements which have subsequently been implemented. What was the impact of the capital projects and to what extend did the projects alleviate the system integrity issues?

Response:

(a) In 2016, NRG had projects to upgrade the Union Gas Bradley Station ($460,000), construct a pipeline from the Bradley Station to the Wilson Line ($855,000), and construct a pipeline from the existing Putnam Station to Colloden Line ($570,000). In 2017, NRG extended the Springwater Road pipeline from south of Orwell to John Wise Line ($292,000). These projects were completed in their respective years.

(b) As the projects listed in response to (a) above were completed in 2016 and 2017, their capital costs were added to the rate base in those years and as such the depreciated value is included in ENGLP's 2020 rate base.

(c) Based on recent operating history, the projects identified in (a) were successful in alleviating the low pressure issues identified in the areas of Brownsville and Aylmer.

2-STAFF-12
Reference: **Exhibit 2 / Tab 1 / Schedule 1/ Pg. 5 / Table 2.2.1-2**

Request:

In the Gross Plant by Uniform System of Account table, the cost of "Mains" has increased from $8.5 million in 2015 to $10.6 million in 2016 and $11.3 million in 2017.

Please explain the substantive increase in the value of mains in 2016 and 2017. What projects were undertaken in 2016 and 2017 and what benefits did the projects provide?

Response:

The capital additions for Mains in 2016 and 2017 were $2,048.7 thousand and $726.4 thousand, respectively. These additions were primarily to address system integrity issues as further described in ENGLP's response to 1-STAFF-11.

2-STAFF-13

Reference: **Exhibit 2 / Tab 1 / Schedule 1/ Pgs. 6-7/ Tables 2.2.1-3 and 2.2.1-4**

Request:

The depreciation amounts for 2018, 2019 and 2020 are different in the above two referenced tables.

Please reconcile the values for the above noted years and explain the differences, if any.

Response:

The difference in depreciation expense in Table 2.2.1-3 and 2.2.1-4 relate to contributions. The depreciation expense total in Table 2.2.1-3 includes contributions whereas the depreciation expense total in Table 2.2.1-4 is net of contributions. The table below provides the reconciliation between Table 2.2.1-3 and 2.2.1-4 as filed in the original application.

Table 2-STAFF-13-1
Depreciation Expense Reconciliation
($ thousands)

		A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**	D **Reference**
1	Depreciation Expense	(1,154.4)	(1,290.6)	(1,151.8)	Table 2.2.1-3, row 8
2	Depreciation Expense	(1,151.8)	(1,271.3)	(1,136.1)	Table 2.2.1-4, row 25
3	Depreciation Expense related to Contributions	(2.6)	(19.3)	(15.7)	Table 2.2.1-4, row 24
4	**Total (row 2 + row 3)**	**(1,154.4)**	**(1,290.6)**	**(1,151.8)**	

2-STAFF-14

Reference: **Exhibit 2 / Tab 1 / Schedule 1/ Pg.13**

Request:

The application shows $72,000 in contributions from customers related to new service connections in the 2020 Test Year.

Please provide further information on the contributions and the type of customers that will be making the contributions.

Response:

ENGLP anticipates customers in Rate 1 through Rate 5 will be contributing to service connection contributions. ENGLP is proposing in Exhibit 8, Tab 2, Schedule 4, page 16 a minimum fee to customers of $100 for Installation of Service Laterals. Additional fees are calculated based on specific applicant circumstances including actual distance from the property line, length of pipe required, and customer specific requirements. The charge reflects the cost for labour, equipment and materials required for the distance and restoration to property. ENGLP outlines the conditions of establishing a price for customers in Exhibit 8, Tab 3, Schedule 2, page 5.

2-STAFF-15
Reference: Exhibit 2/ Tab 1/ Schedule 1/Pg. 18

Request:

EPCOR uses EPCOR Inc.'s burden rate at the corporate level to recover employee benefits.

(a) Please explain how EPCOR ensures that this burden rate is the appropriate rate to use and whether it is reflective of actual burden rates applicable to EPCOR's Aylmer operations.

(b) Has EPCOR determined what its actual burden rate is? If yes, please state the burden rate.

(c) Please quantify the amount of burden that was capitalized from 2011 to 2020, if available.

Responses:

(a) ENGLP Aylmer's staff have similar levels of employee benefits to other employees of the EPCOR Utilities Inc. business units, including, CPP, EI, medical, dental, disability, employee retirement costs, etc. Similarly, ENGLP Aylmer's staff have similar vacation entitlement, statutory holidays and other items which would also be included in the burden calculation. In addition, as noted in the response to (c) below, the amount of burden on an annual basis is not significant and any minor discrepancies which may exist between the burden rate used and an ENGLP Aylmer specific burden rate would be highly insignificant (for example a 5% difference in the total burden rate would have had an approximate $8,000 difference in burden capitalized in 2018).

(b) As noted in Section 2.4.2 of Exhibit 2, Tab 1, Schedule 1, ENGLP Aylmer does not have a separate burden calculation and uses the corporate-wide burden rate for all of EPCOR Utilities Inc. business units. EPCOR Utilities Inc. 2018 Actual burden rate was 42.3%.

(c) The table below shows the burden capitalized for the 2018A, 2019 Bridge Year and the 2020 Test Year. EPCOR cannot confirm NRG's capitalization procedures and policies and given the limited historical financial records EPCOR is unable to provide a breakdown of the capitalized burden amounts, if any, for 2011 to 2017.

Table 2-STAFF-15-1
2018-2020 Capitalized Burden
($)

	A **2018 A**	B **2019 Bridge Year**	C **2020 Test Year**
1 Total Capitalized Burden	70,482	60,474	60,474

2-STAFF-16

Reference: **Exhibit 2/ Tab 1/ Schedule 1/Pg. 19**
Exhibit 2/ Tab 2/ Schedule 2/Pg. 6

Request:

The Capitalization for Regulatory Accounting Purposes in Schedule 2 uses contra-asset accounts for recording capital contributions. This differs from that described in Schedule 1, which records capital contributions under deferred revenues.

(a) Please clarify what is EPCOR's accounting treatment of capital asset contributions in the rate application.

(b) If deferred revenues is not used, please explain why not.

Response:

(a) EPCOR's accounting treatment of capital asset contributions is as described in paragraph 55 of Exhibit 2, Tab1, Schedule 1. Specifically:

> For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates.

The Regulatory Accounting Procedures document noted in Exhibit 2, Tab 2, Schedule 2 will be updated with procedures followed for ENGLP's Aylmer operations.

(b) See ENGLP's response to (a) above.

2-STAFF-17

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.3**

Request:

EPCOR has indicated that in 2018 it completed a customer engagement survey to gather feedback from customers regarding investment in the distribution system and services. The survey was administered directly by EPCOR to customers and open to all customer rate classes.

(a) Please explain how EPCOR was informed from the results of the customer engagement survey in developing the Utility System Plan (USP).

(b) Were respondents provided any scenarios in the survey where they were asked to make trade-offs between a rate increase and expenditures to maintain system reliability or replace aging infrastructure?

(c) Were respondents provided any rate impact estimates of the proposed capital expenditures? Was their feedback sought on projects that should be deferred or reprioritized? If no, why not?

(d) Did EPCOR seek input from survey participants on the type of outcomes that customers expect from investments in the distribution system?

(e) Did EPCOR seek customer input on the proposed enhancements to the distribution system (new capital projects) and operations (IT, billing, building renovations)? If no, why not?

(f) How did the customer engagement survey assist in establishing the objectives outlined in the Renewed Regulatory Framework in terms of demonstrating value for money and the provision of services in a manner which is responsive to customer preferences?

(g) Were there any changes made to the USP as a result of the feedback provided in the customer engagement survey?

Response:

(a) The November 2018 survey collected data on what was most important to ENGLP's customers. These results informed ENGLP in developing the USP to prioritize items important to customers including: keeping rates/bills low, investment in infrastructure and technology.

Customer responses indicated that service reliability was of importance to customers which informed the USP capital plan to prioritize investment in the Belmont and Lakeview reinforcement projects to address system integrity concerns. The USP also addresses improvements to reliability and safety through the project to upgrade the SCADA system and field instrumentation to improve the monitoring and control capability of the system. This system will allow pressures and flows to be automated and alarm monitored to notify operating staff in the event of a system pressure deviation.

Based on responses that customers would likely use an e-billing system (28% of those responding "likely" and 41% responding "very likely") ENGLP included projects in the USP aimed at modernizing technology to better serve the customer such as the implementation of the UMS and Workforce Management software program.

(b) The questions in the November 2018 survey focused on asking customers to provide their views as to the most important aspects of their gas service. The questions did not provide scenarios asking customers to make trade-offs between priorities.

(c) The November 2018 customer engagement survey did not reference specific capital projects or expenditures. As the first customer engagement survey performed be ENGLP under its ownership, the survey was intended to satisfy a number of topics to inform the USP and test business plan assumptions on a range of topics including: customer importance, ENLGP brand recognition, system reliability, safety, and customer engagement and technology preferences. In addition, information on the proposed enhancement projects was not finalized until after receipt of Cornerstone's report on the System Integrity Study in December of 2018.

Customers were informed of bill impacts and capital projects at the OEB Community Meeting held on March 19, 2019. ENGLP has not received customer feedback on this matter at this time.

(d) ENGLP sought to understand with the survey what is most important to customers. Aside from low bills, the second most important response was reliability of service. This expectation of consistent gas service leads ENGLP to propose projects that reinforce system integrity and reliable gas supply.

(e) The survey did not ask customers for input on specific capital projects other than to ask customers how likely they would use an e-billing system as noted in response to (a) above. As noted in response to (c) above, the survey was intended to inform ENGLP on a number of areas.

(f) The OEB's Renewed Regulatory Framework outcomes-based approach is to emphasize results rather than activities to respond to customer preferences, to enhance productivity and to promote innovation.[1] Respecting customer's preferences and the importance to keep rates/bills low, ENGLP selected the most cost effective solution to the system integrity issues as reflected in the USP.

Promoting innovation and value for money, ENGLP's proposed capital projects to modernize technology systems and networks will enhance cyber security and secure customer database information. Investment in bill design has added value to customers with presentment of historical consumption information in an easy-to-read graphical format. This information can help customers analyze their consumption towards conservation efforts. An example of this new bill format is provided in Exhibit 1, Tab 3, Schedule 11, page 1. The development and implementation of online e-billing feature and the use of email as a communication method, aligns with customers' preferences as indicated from the survey.

(g) As noted in the response to (c) above, the System Integrity Study and USP development were ongoing at the time the survey was completed. ENGLP cannot identify a specific change to the USP that resulted from the survey responses; however, as noted in the answers above the responses informed the final USP in a number of ways.

[1] Renewed Regulatory Framework Report, p. 2.

2-STAFF-18
Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.6**

Request:

In the USP, EPCOR has noted that a complete and accurate asset registry, or inventory is key to the process. As the utility continues to build upon the recently implemented Utility Management System and workflow management software and GIS capabilities, it will be better positioned for the future.

Please confirm whether an asset registry has been completed for the USP. If not, please provide timelines for completing the asset registry.

Response:

Asset information, as provided by NRG upon ENGLP's acquisition of the assets, is currently maintained in multiple forms, locations and systems. The compilation of the information for all asset categories into a form consistent with an asset registry under common industry practices and *ISO 55000 Standards for Asset Management* is ongoing.

Given the number of individual assets to manage and the renewal/replacement requirements legislated by Measurement Canada, detailed asset information for meters in service is compiled and maintained within the billing system from the time it is placed into inventory, into service and subsequently removed for decommission.

As stated in the USP, Section 2.1 on page 4 of Exhibit 2, Tab 3, Schedule 1, ENGLP will continue to work towards the implementation of an asset management framework consistent with ISO 55000 Standards for Asset Management. This includes completing an asset registry. ENGLP plans to have a framework in place for input into the USP for its next cost-of-service rate filing.

2-STAFF-19

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Figure 2.2.3-2/ Pg.10**

Request:

The figure provides information on the age of the pipelines in the distribution system. A majority of the pipeline system is fairly new and installed in 2010 or later.

(a) Please explain the overall condition of the distribution system considering that it is fairly new.

(b) How has the age of the distribution system impacted maintenance spending for the planned period?

Response:

(a) ENGLP's distribution system is comprised primarily of polyethylene (PE) mains and service lines installed within the last two decades. With a proposed useful life of PE pipe (approximately 40 years), the majority of the pipelines in the distribution system are in the early to mid-point of the expected service life.

(b) As the majority of the distribution piping network is early in the expected service life, system renewal makes up a relatively small proportion of the forecasted capital investment in this asset category as demonstrated by the forecasted spending in Table 2.5.3-2 on page 21 of Exhibit 2, Tab 1, Schedule 1. Similarly, the anticipated spending for other corrective maintenance of the distribution piping network is minimal, as reflected in the in the forecasted OM&A spending.

2-STAFF-20

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.14**

Request:

EPCOR has noted that in 2018 the forecasted total for capital investments related to system access includes a $600,000 capital expenditure to increase the capacity of the IGPC metering and regulating station.

Please confirm that the cost of the above spending was allocated to the IGPC rate class.

Response:

Confirmed.

2-STAFF-21

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.15**

Request:

EPCOR has proposed two capital projects (Belmont and Lakeview Reinforcement) to resolve system integrity issues identified in the Cornerstone report. The total capital spending on the two projects is $796,000. Both projects are expected to be started and completed in 2019, and the asset in service by December 31, 2019. EPCOR has further noted that the Lakeview Reinforcement Project is contingent upon the successful negotiation of a gas purchase agreement with a third-party.

(a) Please confirm that the implementation of the two projects will resolve the system integrity issues identified in the Cornerstone report.

(b) The project is contingent on the successful negotiation of a gas purchase agreement with a third party. Please provide the annual quantities that would be required under such a gas purchase agreement. What would be the terms of such a purchase agreement?

(c) Would the gas purchase agreement be subject to Ontario Energy Board approval?

(d) What is the current status of the negotiations? Has EPCOR signed any Letter of Intent to purchase the local gas? If yes, please provide details.

(e) Please describe the impact on the EPCOR distribution system if the two projects are not in service by December 31, 2019?

(f) Please confirm that the current estimate for the two capital projects in $796,000. Are the capital costs different from the capital cost estimates provided in the Cornerstone System Integrity Study? If yes, please explain the variance.

(g) With respect to the Belmont Reinforcement Project, does the proposed project specifications meet the forecasted customer growth in the Belmont area and the low pressure issues identified in the Cornerstone report?

(h) In the opinion of Cornerstone, are the proposed initiatives sufficient to resolve the system integrity issue?

Response:

(a) Confirmed. The two projects, Belmont Reinforcement Project and Lakeview Reinforcement Project, will resolve the system integrity issues identified in the Cornerstone report.

The Belmont Reinforcement Project consists of replacing approximately 5 km of existing 2" main with 4" main. This project is expected to alleviate the current low pressure in the Belmont area and accommodate the projected growth.

The Lakeview Reinforcement Project includes construction of approximately 1 km of new main and the associated regulator and meter stations. This project is expected to alleviate the low pressure in the region and provide the capability to meet the forecasted growth. This reinforcement project is contingent on the successful negotiation of a new supply agreement with a local producer.

(b) The intention of the local supply is to contract for a volume of gas to solve a low pressure problem in the winter time during peak periods and meet the 5 year growth requirements. While still subject to ongoing negotiations, ENGLP anticipates contracting for a contract demand of up to 1,500 GJ/d from the local supplier. Annual volumes purchased will be dependent on the area daily gas demand, so it is difficult to estimate at this time how much of this annual demand will be met from new local production versus gas purchased from Enbridge.

While still subject to ongoing negotiations, the gas purchase agreement is expected to include additional key terms such as:

- Conditions precedent for both parties (e.g., construction of the necessary facilities to connect the supply),

- A 5 year term with ENGLP having ongoing renewal rights,
- Firm supply agreement,
- A pricing mechanism,
- Gas quality and technical specifications (delivery point location, min/max pressure requirements), for the supply,
- Ongoing reserves assurances,
- Upstream facility planned maintenance restrictions during winter months,
- Typical representations and warranties,
- Custody transfer and measurement responsibilities,
- Billing and payment terms, and
- A dispute resolution mechanism.

(c) The gas supply agreement to support the Lakeview Reinforcement is currently being negotiated (i.e., not in final form). It has not yet been determined whether ENGLP will elect to file the gas supply agreement for pre-approval pursuant to the Board's *Filing Guidelines for Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts* (per EB-2008-0280).

(d) Negotiations are ongoing. ENGLP has not signed a Letter of Intent, nor does it anticipate signing a Letter of Intent. Parties are negotiating the specific terms of a gas purchase agreement.

(e) Each of the two respective areas requires a reinforcement project to alleviate existing low-pressure problems, which jeopardizes the security of supply to customers in the area under peak day conditions.

(f) Confirmed. The current estimate for the Belmont and Lakeview projects is $796,000. The capital costs comparisons between the Cornerstone System Integrity Study and the USP is shown in Table 2-STAFF-21-1 below.

Table 2-STAFF-21-1
Comparison of Cost Estimates
($)

		A **Belmont Reinforcement**	B **Lakeview Reinforcement**	C **Total**
1	Cornerstone	478,436	1,181,544	1,659,980
2	USP	439,000	357,000	796,000
3	**Variance**	**39,436**	**824,544**	**863,908**

The Belmont Reinforcement Project cost estimate was reduced by $39,436 after a review of Cornerstone's cost methodology for internal costs related to project management which were higher than ENGLP's forecasted costs.

The estimate for the Lakeview Reinforcement Project prepared by Cornerstone was prepared prior to detailed discussions with the owner of the local gas supply. Cornerstone's estimate included an allowance for a more complex regulating and metering station based on the higher supply pressure assumed. After ENGLP undertook a more comprehensive review and discussion of requirements with the third-party owner, it was determined that a smaller, less complex and lower cost regulating station would likely suffice. The cost estimate included in the USP was reduced by $824,544 to reflect this.

(g) Yes, the proposed Belmont Reinforcement Project specifications meet the forecasted customer growth in the Belmont area and the low pressure issues identified in the Cornerstone report.

(h) Yes, in Cornerstone's opinion the proposed initiatives are sufficient to resolve the system integrity issue.

2-STAFF-22

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.15 and Cornerstone Study Exhibit 2/Tab 3/ Sch. 2/ Pg. 18**

Request:

In the USP, EPCOR has noted that approximately 5 km of the Westchester Bourne pipeline between the Belmont Station and the village of Belmont is currently constructed of 2 inch PE pipe and the balance 4 inch. EPCOR plans to replace this 2 inch section with a 4 inch PE pipe, reducing the pressure drop and addressing the pressure issue at Belmont. In the Cornerstone Integrity Study, the report considered a number of options to address system integrity issues. One of the options was to replace all 2 inch piping running North-South along Westchester Road that feeds the Northern regulator station of Belmont. The report indicated that there are two sections of the 2 inch pipe totalling 3.1 km. Cornerstone has recommended upsizing the two sections of pipe to 4 inch to match the rest of the mainline along Westchester in order to improve pressure along the section of the pipe.

(a) Please confirm that the project referred to in the USP and the above option recommended in the Cornerstone integrity study is identical. If there are any differences, please explain.

(b) The total length of the pipeline to be upsized is different in the USP (5 km) and the Cornerstone report (3.1 km). Please explain the reasons for the difference in the length of the reinforcement.

(c) Is the cost of the project provided in the USP and Cornerstone report the same? If there are any differences, please explain and quantify the variance by cost components.

Response:

(a) Confirmed. The Belmont Reinforcement Project referred to in the USP and the above option recommended in the Cornerstone system integrity study, identified as Project 3, are identical.

(b) As the system integrity study progressed, the estimated total length of pipeline to be upsized was increased to approximately 5 km based on an updated understanding of conditions in the field. The estimated total length of approximately 5 km was used in both the project cost estimate provided in the Cornerstone report and included in the USP.

(c) The cost of the project provided in the USP ($439,000) is less than the estimate provided in the Cornerstone report ($478,436). The project cost included in the USP is based on the Cornerstone estimate but with reduced internal costs related to project management.

2-STAFF-23
Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.16**

Request:

System modelling completed by Cornerstone as part of the 2018 System Integrity Study showed materially lower operating pressure in the south of the system during periods of peak demand. This confirms recent observations by operating staff, who have noted pressures less than 40 psig, and approaching the 30 psig minimum design pressure in the area. EPCOR has indicated that the situation will only get worse as demands increase and production from the connected wells continues to decline.

(a) Please provide the required pressure of pipelines in the south to meet peak demand.

(b) EPCOR has noted that the Lakeview Reinforcement project is contingent on the successful negotiation of a gas purchase agreement with a third party. Does EPCOR know the remaining life of the connected wells?

(c) Has EPCOR considered other potential solutions that are not dependent on local production?

Response:

(a) The minimum design pressure in this part of the system is 30 psig. The proposed supply from the local producer will allow this minimum design pressure to be met.

(b) The owner of the wells proposed to be connected through the Lakeview Reinforcement project has provided ENGLP with information indicating that a review of the reserves at the end of 2017 showed the remaining Total Proven Reserves from the wells that would be used to serve ENGLP was 18,096 MMcf. The Total Proven Plus Probable reserves from these wells was 21,722 MMcf. ENGLP is aware that the producer has other sales volumes from these wells but ENGLP does not know the annual volume of gas that would be sold to other customer(s). ENGLP is considering a contract demand of up to

1,500 GJ/d (1,422 Mcf/d), to meet peak day demands, although it is unclear what the annual purchase volumes would be at this time. Assuming that a) all of the reserves would be used to serve ENGLP, b) ENGLP committed to a contract demand of 1,422 Mcfd, and c) took gas at 100% load factor (519 MMcf annually), the Total Proven Reserves would result in a reserve life of 34.8 years and using the Proven Plus Probable Reserves would result in a reserve life of 41.8 years.

ENGLP also understands that the local producer has additional wells that could be integrated into the system that would be used to supply ENGLP. This would extend the life of the reserves. The commercial arrangement that ENGLP is negotiating with the producer will require the producer to annually provide a current independent reserves report. ENGLP is proposing an initial contract term of 5 years with ongoing renewal rights. Any term extensions would be subject to ENGLP being satisfied that sufficient reserves exist to meet its contract demand.

(c) As outlined on page 17 of the Utility System Plan (Exhibit 2, Tab 3, Schedule 1), ENGLP reviewed two options that are not dependent on local production. The option of adding a trailered compressed natural gas (CNG) on-system storage in the south of the system, and the option of installing a steel pipeline to move gas at a higher pressure from a transfer point from Enbridge Gas' Union South system were both considered. The estimated costs of each of these options were $2.5 million and $10.0 million, respectively, far exceeding the proposed option.

2-STAFF-24
Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.17**

Request:

The Ontario Ministry of Transportation has indicated that it intends to start construction on improvements to the interchange of Westchester Bourne and Highway 401 in 2019. The project requires EPCOR to relocate the 6 inch IGPC steel pipeline and a 4 inch PE main that will be in conflict. The estimated capital cost to complete the relocation is $1.2 million of which the Province will contribute $536,000.

(a) Please provide additional information on the 4 inch PE main and the class of customers it serves.

(b) Please provide separate costs for relocating the IGPC pipeline and the 4 inch PE main.

(c) Please confirm that the cost of relocating the IGPC pipeline will be allocated to the IGPC rate class. If not, please explain the reasons for not doing so.

Response:

(a) In addition to the 6 inch IGPC steel pipeline, approximately 30 m of 2 inch PE pipe and 50 m of the Westchester Bourne pipeline 4 inch PE pipe will also be relocated. The PE pipe serves customers in Rate Classes 1 through 5. Costs associated with the realignment of the PE pipe were inadvertently allocated to Rate 6 in the Application and as such, the total cost of the realignment project was fully allocated to Rate 6. Table 2-STAFF-24-1 below provides a breakdown of the updated project cost between the 6 inch steel line and the PE pipe.

(b) ENGLP received final plans for the rework of the interchange from the MTO in March 2019 and is in the process of performing design work for the pipeline relocations. Based on preliminary budgetary contractor pricing, ENGLP has updated its project cost estimate as reflected in Table 2-STAFF-24-1, below.

Table 2-STAFF-24-1
Pipeline Realignment at Highway 401 Interchange Project Breakdown
($)

	Cost Breakdown	A **IGPC Main**	B **PE Main**	C **Total**
1	Materials	47,000	2,000	49,000
2	Engineering	61,000	8,000	69,000
3	Labor & Equipment	587,000	81,000	668,000
4	**Total**	**695,000**	**91,000**	**786,000**
5	MTO Contribution (50% of Labor & Equipment)	294,000	41,000	335,000
6	**Total Net of Contributions**	**401,000**	**50,000**	**451,000**

ENGLP proposes to update the Application to reflect the revised project cost and breakdown shown in the table above. See response to 9-STAFF-78 for the updated revenue requirement, rates and bill impacts resulting from these changes.

(c) Confirmed. The cost of relocating the 6 inch steel pipeline servicing IGPC will be allocated to the IGPC rate class. As noted in ENGLP's response to (b) above, the cost of relocating the PE pipelines will be allocated to Rate Classes 1 through 5.

2-STAFF-25

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pgs.18-19**

Request:

EPCOR intends to upgrade the field instrumentation and the supervisory control and data acquisition (SCADA) system to allow field measurements to transfer in real time to a central SCADA computer, creating a single operator interface to monitor the system locally or remotely. The project will be implemented in phases from 2019 through 2024.

(a) Please confirm that the total capital cost of the SCADA upgrade project is $585,000 for the period 2019 through 2024.

(b) What will be the annual operating costs of updating the system during the project implementation period?

(c) Why are the capital costs higher in 2019 and 2020?

Response:

(a) Confirmed. The total capital cost, based on preliminary engineering estimates, for the SCADA upgrade project is $585,000 for the period 2019 through 2024.

(b) ENGLP is preparing to open discussions with vendors in 2019 to further refine the project scope and cost estimates, including annual operating costs. Annual operating costs during the project implementation period are not expected to be materially different from current costs.

(c) Capital costs are higher in 2019 and 2020 due to the larger project scope to be completed in those years. As stated in the Utility System Plan, in 2019, ENGLP plans to install the central SCADA server hardware and software, communications equipment and integrate the seven metering and regulating stations at the transfer points with Enbridge Gas. In 2020, additional meters at approximately 10 key locations will be tied to the system. For the years 2021 through 2024, existing and new flow and pressure instrumentation will be tied to the system, a few points each year based on risk and benefit.

2-STAFF-26

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pgs. 21-25**

Request:

EPCOR has provided information on capital programs from 2019 to 2024 for mains additions, service additions, meters, regulators and other infrastructure.

Please provide historical data for the years 2015 to 2018 for mains additions, service additions, meters replacement, regulating stations, regulators and fleet replacement.

Response:

See Table 2-STAFF-26-1 below. ENGLP is unable to breakout the capital additions of regulators and regulating stations separately.

Table 2-STAFF-26-1
2015-2018 Capital Additions
($ thousands)

		A	B	C	D	E
		2015 A	**2016 A**	**2017 A**	**2017 Stub**	**2018 A**
1	Main Additions	188.5	2,048.7	726.4	9.1	553.5
2	Service Additions	56.5	84.7	117.6	46.1	268.4
3	Meters Replacement	276.0	123.0	81.4	14.6	368.9
4	Regulators / Regulating Stations	14.5	69.5	7.0	-	98.8
5	Fleet Replacement	15.6	86.7	0.4	-	107.0

2-STAFF-27

Reference: **Exhibit 2 / Tab 3 / Schedule 1/ Pg.13 and pgs. 24-26**

Request:

EPCOR has provided information on the replacement of various assets including mains additions, regulating stations, natural gas regulators, small tools and equipment and computers and office equipment. In case of all these capital projects, EPCOR has noted that the forecast annual capital spend is based on management judgement and historical spend. However, in the planning process overview (pg.13) EPCOR has indicated that individual capital investments are selected and prioritized based on asset condition, forecasted growth, risk and benefit to the customer.

(a) Please explain the inconsistency in the evidence as pointed above.

(b) Has EPCOR completed an asset condition assessment of each of the assets listed above? If yes, please provide the asset condition assessment.

(c) Why is EPCOR relying on management judgement as a criteria considering that measureable and objective criteria are available to determine asset replacements?

Response:

(a) The information provided in Exhibit 2, Tab 3, Schedule 1 pages. 22-26 for the asset types mentioned above (mains additions, regulating stations, natural gas regulators, small tools and equipment and computers and office equipment) relate to the annual program for each asset types rather than specific projects. ENGLP has not completed an asset condition assessment of all of the assets listed above and understands that no such assessment was completed by NRG. Accordingly, in the absence of this data ENGLP has relied on management judgement and historical spend to determine the forecasted annual spend provided for each program.

The planning process described in Exhibit 2, Tab 3, Schedule 1, page 13 speaks to individual capital projects (as opposed to the annual programs provided on pages 22-26). In conjunction with developing its annual capital budget, ENGLP refines the program estimate by forecasting specific projects to undertake as part of the annual program. The projects are then further reviewed and prioritized through the Project Charter process prior to initiating the projects. It is through the development of the annual budget and Project Charters that ENGLP identifies and prioritizes projects based on asset condition, forecasted growth, risk and benefit to the customer. In the absence of a complete asset condition assessment, ENGLP relies on information available (i.e., available asset records, recent operating/system issues, etc.) to asses asset condition for the purposes of identifying and prioritizing projects.

(b) As noted in ENGLP's response to (a) above, ENGLP has not completed an asset condition assessment of all of the assets listed above. Asset condition assessments are an element of the asset management process. As noted in the USP, the asset management framework and asset management plans, founded on the principles of continuous improvement, will continue to evolve over time based on requirements and priorities.

(c) See ENGLP's response to (a) above.

2-STAFF-28

Reference: **Exhibit 2 / Tab 3 / Schedule 2/ EPCOR Aylmer System Integrity Study**

Request:

EPCOR has provided a system integrity study completed by Cornerstone Energy Services.

(a) Please describe the process undertaken to select Cornerstone Energy Services to complete the system integrity study.

(b) Why did EPCOR decide to undertake a second system integrity study?

(c) Please provide the experience of Cornerstone Energy Services in conducting gas-related engineering studies.

(d) What was the total cost of the Cornerstone system integrity study?

Response:

(a) Cornerstone Energy Services has proven itself to be cost competitive in previous competitive bids, including participating in the due diligence undertaken by EPCOR when considering the acquisition of NRG, the predecessor of ENGLP. In determining the best engineering firm for the system integrity study, ENGLP provided Cornerstone with a scope of work and requested a competitive bid. Experienced project management / engineering staff then reviewed Cornerstone's bid in-line with ENGLP's procurement process to determine whether it was compliant with the scope of work and whether the overall cost was reasonable. Cornerstone was then selected to complete the system integrity study and was able to incorporate the knowledge it had developed when completing the due diligence related to the acquisition of NRG in completing the system integrity study.

(b) ENGLP decided to undertake a second system integrity study after a comprehensive review of the system integrity study completed by SNC-Lavalin for NRG. After that review, ENGLP concluded that the study did not adequately address the range of potential solutions to ongoing concerns regarding system pressures in parts of the distribution system. In particular, ENGLP was of the view that there were viable alternatives to continuing to use natural gas priced at above market rates to support system pressure in parts of the system.

(c) See 2-STAFF-28 Attachment 1 for information on Cornerstone's related experience.

(d) The total cost was $119,273.

Who We Are

Cornerstone Energy Services, Inc. provides engineering, survey and land services to the energy infrastructure marketplace. We provide a broad range of services critical to the initial phases of projects, right through completion and documentation. These services include: process, civil, mechanical and I&E engineering, project management, survey and mapping, and Right-of-Way acquisition. We have expertise and experience in both long linear projects as well as single-site facilities. Our clients are developers and operators of oil and gas pipelines and electric transmission lines.

At Cornerstone, the strength of our business is based on adherence to fundamental values:

- **Safety of the public, our employees and our clients;**
- **Advocacy** for the interests of our clients; and
- The **Integrity** of our operations.

Our current staff consists of Mechanical, Electrical, Civil and Survey Engineers, Designers, Drafters, Mappers and Photogrammetrists, Land Surveyors, Right-of-Way Acquisition Specialists, Safety Professionals, and the support staff necessary to deliver high quality results in fast-paced project environments.

We have offices in Massachusetts, Texas, Maine, West Virginia, Connecticut, New Hampshire, New Jersey, Florida, and Idaho . Note that we have Licensed Surveyors in MA, ME, NH, CT, NJ, PA, OH, VT, WV and as well as Licensed Engineers in MA, ME, NH, RI, CT, VT, NY, PA, NJ, MD, WV, NM, VA, and TX.

Our ownership team and staff have decades of experience serving the Energy Infrastructure marketplace and have helped develop significant pipeline and power line projects all over the country.

Cornerstone is proud to list these fine companies as clients:

- Black & Veatch
- Centurion Pipeline, L.P.
- Clean Energy
- Columbia Gas of Massachusetts
- Connecticut Light and Power
- Daniel O'Connell's Sons
- Direct Energy
- DTE Energy
- Eversource
- GDF Suez
- Hess Corporation
- Iroquois Transmission Pipeline
- Irving Oil
- Kleinfelder
- Momentum
- National Grid USA
- Newark Energy Center
- Northeast Utilities
- Norwich Public Utilities
- Occidental Petroleum Corporation
- PAR Electrical
- Parsons Brinkerhoff Power
- Precision Pipeline
- Power Engineers
- Public Service of New Hampshire
- Repsol USA
- R.H. White
- Stonewall Gas Gathering, LLC.
- Summit Utilities
- Supreme Industries
- TetraTech
- TRC
- Tri-Mont Engineering
- UGI Energy Services
- United Illuminating
- Western Mass Electric Company
- Woodland Pulp LLC
- XNG
- Yankee Gas

What Makes Us Different

Cornerstone is not another re-branded supermarket and sports stadium design company. We are the real deal, working on pipeline and power line projects every day. Cornerstone sets itself apart from others in the industry by providing services on the following basis:

- **Quality Services**
  - Applying up-to-date technology and tools in survey and design development;
  - Assigning qualified and trained staff to the project team at the management, engineering and technician levels;
  - Capturing the value of decades of experience regarding what works and what does not in each design we produce or facility we support; and,
  - Recognizing the unique nature of the energy delivery industry: never compromising the safety of our work, neither in its performance nor in its lasting effects after we are done.
- **Real Cost Efficiency**
  - Would you rather reduce your engineering costs by 10%, or reduce your total project costs by 5%? Perhaps both? Delivering value to our clients drives our decisions on a daily basis;
  - Energy projects meet very real challenges that are time sensitive. We provide services that are delivered on time to allow our clients to plan with confidence; and,
  - Applying the most effective technology and techniques to provide the highest standard of services without unnecessary investment of time and money.
- **Superior Design**
  - Not all energy infrastructure designs are equal. Through our broad and deep experiences in this business, we deliver solutions that deliver what the client values: safety, reliability, low life-cycle cost, and trouble free operation long into the future; and
  - Not all energy designers are the same. We endeavor to operate and maintain a company that attracts and retains the best practitioners in their fields. We do this by always valuing the contributions of the staff and investing in their futures. We do not let other markets and non-core businesses distract us from providing superior services to this dynamic, and critically important industry.

Cornerstone provides many key development services under one roof, and one contract. Clients have told us that this greatly benefits them in their ability to manage and execute their projects in an efficient manner, leading to project cost savings and high-quality, on-time performance. We also are adept at teaming with environmental firms, attorneys, other consultants, builders, and suppliers to drive project success.

Cornerstone
Energy Services

Natural Gas Project Experience (Excludes LNG)

Summit – KV1

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Design of Approximately 70-miles of steel transmission pipe and approximately 65-miles of HDPE distribution pipe. This project included 9 main line valve sites, 6 pressure regulator sites and 1 pig farm.

The 9 main line valve sites were designed with automatic line break valves and SCADA connectivity, the design included electrical, instrument and control design plans. In addition to design, Cornerstone was responsible for construction support, start-up and commissioning.

The 6 regulator stations have an inlet MAOP pressures of 1440 PSIG and an outlet MAOP of 99 PSIG. Cornerstone handled all aspects of the design. Special challenges included raising one site above the flood plain, design for urban and suburban areas, and standards development (Summit Natural Gas of Maine is a new gas company). Cornerstone was also responsible for land acquisition, procurement support, permit acquirement from multiple town agencies, construction support, start-up, and commissioning.

Summit – Pittston Meter Station

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Design of a Spectra Energy specification meter station (5 MMSCFH) at Pittston, ME which feeds the Summit KV1 system.

Summit – KV2

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Design of Approximately 25-miles of HDPE pipeline connected to Summit KV1 system.

Summit – KV2 Bridge Crossings

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Complete design, material specification, procurement support, and permit acquirement for 2 bridge crossings located in Waterville, ME.

Summit – CFY

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Design of approximately 50-miles of 4, 8, & 12-inch pipe and approximately 180-miles of 2-inch pipe connected to Summit CFY system.

Summit – Cumberland Meter/Regulator Station

Reference: Helen Ayotte, Manager of Engineering, Summit Natural Gas of Maine (207) 621-8000 x454

Design of a Spectra Energy specification meter station (20 MMSCFD) at Cumberland, ME. Cumberland Station also includes a pressure regulator system which reduces the inlet MAOP pressures of 1440 PSIG to an outlet MAOP of 99 PSIG which feeds the Summit CFY system.

XNG – Eliot Meter Station

Reference: Matt Campano, Xpress Natural Gas (617) 212-2496

Subcontracted by Daniel O'Connell's Sons, Cornerstone designed a meter station to Spectra specification (18 MMSCFD) in Eliot, ME to feed a CNG trailer filling facility.

Direct Energy – Manheim Meter Station

Reference: Jeremy Bernier, Infrastructure Project Manager, Direct Energy (732) 750-6509

Design of an Iroquois specification meter station (700 MSCFH) in Manheim, NY to feed a CNG trailer filling facility.

Momentum - M3

Reference: Cole Caudill (970) 247-4423

Cornerstone has supported Momentum Midstream with various projects in the Marcellus Shale Region since 2012. Our services have included survey (preliminary, construction and as-built) and mapping (permit drawings, land plats & alignment sheets) for various pipelines in northern West Virginia. Located in Westover, WV our staff has also assisted Momentum with the installation of permanent pipeline markers as well as ROW acquisition.

UGIES

Reference: Tracy Barnes (610) 373-7999 x 243

Cornerstone assisted UGIES with identifying missing data records as well as updated class studies on three pipelines located in Pennsylvania. Cornerstone also provided Engineering support including review and preparation of the CAPEX estimate report for the plan to upgrade the one of the lines from its current MAOP of 720 PSIG to 823 PSIG.

National Grid – Regulator Pit Replacement Project

Reference: Bradford Marx, Associate Engineer, National Grid (781) 907-4009

Design of two regulator pits in East Providence, RI to National Grid specifications. The design challenges of this project was to keep all the services online during construction.

Woodland Pulp

Reference: Steve Strout (207) 427-4026

Design of a 1,800-foot 8-inch new pipeline with MAOP of 1440 PSIG and a custody transfer meter set (700 MSCFH)

HESS – Newark Energy Center

Reference: Pat Williamson (617) 960-4831

Subcontracted by PB Power, Cornerstone developed drawings and procurement packages for Newark Energy Center (NEC). Cornerstone designed a meter station for NEC to Transco/Williams specification (5.1 MMSCFH) with an MAOP of 860 PSIG. Meter was pre-fabricated on a two-piece skid.

Confidential Client (185 miles large diameter high pressure gas transmission in New England)

Cornerstone has prepared a feasibility study for a 185 mile large diameter high pressure gas transmission line in the New England area. The study included: Proposed route, material specification and a cost estimate.

BEC - Bayonne Energy Center

Reference – Ellen Allman, Director Asset Management, MIC Power (775-848-7471)

Design and construction support of a power plant addition to the Bayonne Energy Center in Bayonne, NJ. Added four gas compressors, gas blending skid, cooling skid and ADC building. Project also included commissioning, purge support, procurement and materials tracking.

Cornerstone
Energy Services

Pat Convery, PE, CEng
Principal and Chief Engineer

EXPERIENCE SUMMARY

Mr. Convery has over 33 years of engineering experience working for major system operators, project developers and engineering firms. He has served in many engineering, and project management roles and has experience in construction, inspection, operations, product development, teaching, engineering management and executive management.

He has provided consulting services to operators and developers in the areas of strategic planning, project development, acquisitions, operating efficiency, facility siting (including LNG facility siting) and many other areas. Mr. Convery has led successful design and construction and commissioning of compressor and pump stations, meter & regulator stations, gas distribution systems, LNG plant facilities, LNG plant life extensions, in-line inspection facilities, major pipeline bridge attachments, CNG stations and specialty gas system installations and GIS systems for pipelines.

He has trained and led teams of engineers, designers, drafters, construction forces, material managers, and other professionals in the completion of many safe, highly functional and durable energy infrastructure projects.

SELECTED PROJECT EXPERIENCE

1985 Hanover (NJ) Compressor Station, Compression Engineer
New gas turbine mainline gas compressor station, two units, Solar Centaurs, PLC-based remote controlled, low noise

1986 Southeast (NY) Compressor Station, Quality Control Manager
New gas turbine mainline gas compressor station, two units, Solar Centaur-H, PLC-based remote controlled, fiber optic plant network, very low noise

1987 Gas Aftercooler, Cromwell, CT, Project Manager
After cooler for multi-unit reciprocation mainline compressor station, Honeywell loop controllers, low speed, low noise fans

1988 - 89 Dry low-NOx gas turbine retrofit program, Project Manager
Replacement of several Solar Centaur, H, and Taurus units with SoLoNOx technology, controls retrofits, spare parts management

1990 Compressor Addition, Southeast (NY), Project Manager
Added one Solar Mars/C601 gas turbine package to an existing station with two small turbines. Remote control, compressor noise reduction, low NOx

1991 Compressor Addition, Burrillville, RI, Project Manager
Added two Solar Taurus gas turbine compressors to an existing station with three Clark TLA-8 engines. Common header operation, pulsation analysis and mitigation, measurement systems, PLC- based controls, large volume pressure regulation.

1992 - 94 Chaplain (CT) Compressor Station, Project Manager

EDUCATION

BE(EE), Electrical Engineering, Manhattan College

MSEE, Electrical Engineering, Tufts University

ALM, Government, Harvard University

AREA OF EXPERTISE

Gas and Oil Pipeline Facilities Design

Natural Gas M&R Station Design

LNG Facility Siting & Design

CNG Facility Design

Propane System Design

Economic/Technical Feasibility Studies

Project Development

Gas and Oil System Planning

Instrumentation & Control Systems

REGISTRATIONS/ AFFILIATIONS

Professional Engineer: MA,ME,NH,VT,CT,RI,NY,NJ,TX,NM
Chartered Engineer, MIEI

Member NFPA, Industrial Fire Protection Section, 59A and 56 Technical Committees

OFFICE

Worcester, MA, USA

YEARS OF EXPERIENCE

33

CONTACT

PConvery@CornerstoneEnergyInc.com

New station including two Solar Taurus units. Very low noise, low impact, low-NOx, condensed footprint, PLC based, remote controlled.

1993 Pipeline GIS System Implementation, Project Manager
New GIS system for 300 mile pipeline system including aerial imagery, asset inventory, alignment map generation, ad-hoc reporting, and support for class location determination.

1994 Providence, RI Algonquin LNG Expansion Project, Project Engineer
Regional peaking facility concept including 400 MMSCF/d high pressure sendout (remotely heated), 40 MMSCF/D Liquefaction (16,000 Hp electric motor drive), boiloff compressor system. Project designed and permitted by FERC, not constructed due to shift in business environment.

1997 Providence , RI Algonquin LNG Expansion Project, Project Manager
Added three water bath vaporizers, total output 150 MMSCF/d, boiloff compressor system consisting of two electric driven flooded screw compressors, PLC-based distributed control, safety systems.

1997 British Gas, Project Engineer
Low emissions technology compendium for gas pipeline compressor applications, prepared for BG to assist in system planning.

1998 Maritime & Northeast Pipeline, Phase II meter stations, Project Manager
Design of 14 stations to support distribution of new source of gas from Sable Island, includes one- half of the interconnect at Westbrook and the high-volume delivery station at Dracut, MA.

1998 - 99 Iroquois Eastchester Expansion, Project Engineer
Early stage development planning and design for large scale pipeline expansion, compressor additions, sub-sea routing, densly populated (NYC) routing, capital planning.

1998 Londonderry (NH), Combined Cycle Generation Station, Gas Systems Engineer
Gas fuel metering, regulation, pre-treatment system for new high-efficiency combined cycle plant.

1999 Devon Meter Station, Project Manager
Delivery point to power plant, high pressure, high volume.
2000 Tiverton (RI) Combined Cycle Generating Station, Gas Systems Engineer
Gas fuel metering, regulation, pre-treatment system for new high-efficiency combined cycle plant.

2000 - 2002 Project Manager
New product introduction manager for new technology 14XX semiconductor lasers for Raman optical amplifiers for DWDM communications market.

2002 NSTAR Marlborough Meter Station, Project Manager
Electrical design, ExP MC/MI cable system, limited relay logic, back-up generation.

2003 Huallaga Ethanol Pipeline, Project Engineer
Feasibility study and rout design for 1000-km ethanol export pipeline from the Huallaga river valley across the Andes to the Pacific coast terminal at Bayovar.

2003 Bowline (NY) Generating Station, Project Manager
Design of main fuel gas trim regulators retrofit.

2004 NSTAR Electric Stoughton-Boston 345kV, Project Engineer
Bridge attachment designs for three 8” pipe-type cable in urban environment.

2004 NSTAR Framingham Meter Station, Project Manager
EPC contract for new meter/regulator station, compressed site, direct access from highway, ultrasonic metering, multiple regulation systems, remotely heated gas pre-heat, back up generation.

2004 Keyspan LNG, Project Manager
Dike modifications project, design/build contract.

2004 Keyspan Energy Delivery, Project Manager
Cape Cod winter preparations program, LNG injection site preparations at Chatham, Eastham, & Orleans, MA.

2004 - 2005 Keyspan LNG, L.P., Project Manager
LNG Import terminal development, overall project manager for design and construction of 375 MMSCF/d high-pressure send out, new ship berth, new high volume boil off compressor system, administration building expansion, electric service modernization (dual-feed, 34kV).

2006 ElPaso Energy, Project Manager
Wright Interchange redesign. 400 MMSCFD high-pressure interchange. Design of new hydronic preheat system, regulator replacement, building replacement.

2006 Keyspan Energy Delivery, Project Manager
Everett Interchange, 6 MMSCFH at 22 psig, principle IP feed to Boston. Complete redesign of IP regulator runs.

2007 CMEEC Wallingford, Project Manager
Power plant gas fuel delivery system, Design/Build. High pressure inlet pipeline, metering to Spectra specifications, electric preheat, regulation to Yankee Gas specifications, building, site development.

2007 Spectra Energy, Project Manager
Sandwich, MA M&R Station, Design/Build. New feed to Keyspan on Cape Cod. 4 MMSCFH, metering to Spectra specifications, preheat and regulation to Keyspan specifications.

2007 Spectra Energy, Project Manager
Northeast Gateway Onshore Facilities - Salem Meter Station, Design/Build. Reverse flow direction and add low flow meter run, extend concrete building.

2008 - 2012 Hess LNG, Engineering Project Manager
Weaver's Cove – New LNG import terminal in Fall River Massachusetts, storage, vaporization, trucking, interconnector pipelines, remote berth with sub-sea LNG transfer lines.

2008 - 2012 Hess LNG, Engineering Project Manager
New LNG import terminal in Tarbert, Co. Kerry, Ireland, storage, vaporization, interconnector pipeline, EU procurement regulations.

2009 - 2012 Hess LNG, Engineering Project Manager
Crown Landing LNG – A new LNG import terminal located in Logan Township in New Jersey. Supported process development, CHP strategy, and general engineering issues.

2012 Confidential Client, Consultant
Stranded oil user LNG trucking study feasibility study. Examination of supply options, trucking logistics, and storage/vaporization/utilization equipment requirements for an industrial fuel user in the Northeast US.

2013 PB Power/Hess NEC
Deign of a Williams/Transco specification gas meter station in Newark New Jersey. 5.3 MMSCFD, prefabricated skid construction.

2013 Summit Natural Gas of Maine
Design of a new gas distribution company in the Augusta area, including a Spectra Energy specification meter station (5 MMSCFH) at Pittston, ME; 60 miles of 1440 PSIG transmission line and seven district regulator stations.

2013 Daniel O'Connell's Sons/ XNG

Design of a Spectra specification meter station in Eliot, Maine, 18 MMSCFD.

2013 Kleinfelder/NSTAR
Front End Engineering (FEED) for the replacement of an LNG satellite storage/peak shaving plant in Massachusetts.

2013 Northeast Midstream
Siting analysis for a small-scale LNG liquefier 200,000 gallons per day

2013 RH White
Piping design and code compliance support for new propane installation at Monadnock Regional hospital in Peterborough, NH.

2013 Tetratech/Shell
Value engineering for a major LNG export project in the US.

2013 RH White
Commissioning plan and field support for purge, pack and pickle of an industrial gas distribution system fed from trucked LNG in Florence, VT.

2014 Summit Natural Gas of Maine
Design of a Spectra Energy specification meter station (800 MSCFD), with regulation and preheat for a new gas distribution area in Cumberland/Falmouth/Yarmouth, Maine.

2014 Direct Energy
Design and procurement support for an Iroquois-spec meter station (700 MSCFD) in Manheim, NY.

2014 Engie
Provide conceptual design, CAPEX estimates, optimization studies and project planning for a gas compression facility to feed a large power generation complex.

2014 Tetratech/United Illuminating
Program support for Connecticut Natural Gas and Southern Connecticut Gas LNG plant modernization multi-year capital program.

2014 Centurion Pipeline
Design of crude oil gathering pipeline facilities including hydraulic modeling, traps, metering, tank tie-ins, valve sites, etc. for the Midkiff East and Northwest laterals projects.

2014 Tetratech/Source One/Dartmouth College
Conceptual Design and siting analysis for LNG truck-in and vaporize plant near Dartmouth College in Hanover, NH.

2015 RH White
Propane system design for the Waterbury State Office Complex in Waterbury, VT. Underground storage, electric vaporizer and two stage pressure regulation.

2015 Gexcon USA /HQC/China National Petroleum Company
Working with Dr. Filippo Gavelli of Gexcon, prepare and conduct a training class for ~100 engineers in Beijing to provide familiarity with NFPA 59A standard for LNG facilities.

2015 Centurion Pipeline
Detailed design and project support for a new eight mile crude oil gathering system in the Permian Basin including PD pumps with soft starters, traps, LACT tie-ins and all required design services.

2015 PB Power/Macquarie Infrastructure

Deign of a Spectra specification gas meter station in Bayonne New Jersey. 6.9 MMSCFD, with 7,500 feet of 16” high pressure connecting pipeline to supply a power plant addition at the Bayonne Energy Center.

2015 Liberty Utilities
Provide conceptual facility siting and regulatory support for a new LNG liquefier for utility peak shaving purposes in Fall River, MA.

2015 Tetratech/Confidential Client
Provide conceptual design, CAPEX & OPEX estimates, project plans for a new peak shaving LNG plant to serve a power generator in the western US.

2015 Confidential Client
Conduct desktop and field investigation to quantify structure counts and gas demand in a new potential gas distribution franchise area.

2015 RH White
Design of a relocated high volume service to the central plant at the Mohegan Sun Casino complex in Connecticut to make room for the Earth Hotel development.

2015 EPCOR
Provide conceptual gas distribution design options, CAPEX & OPEX estimates, and project planning services for a potential new gas distribution franchise area on the eastern shore of Lake Huron.

2015 Eversource
Design of a replacement of several older outdoor motor controls with new indoor MCC equipment at an operating LNG peak shaving plant in Acushnet, MA

2016 RH White/Connecticut Natural Gas, Rocky Hill
Provided design and construction support services as part of an EPC Team lead by RH White to replace the sendout pumps at the Rocky Hill LNG facility for Connecticut Natural Gas. Project included innovative pump mounting plan, individual recycle control, AC-AC VFDs, spill containment, and siting study.

2017 RH White/Liberty Utilities, Fall River
Provided design and construction support services as part of an EPC Team lead by RH White to replace the sendout system at Fall River, including new shell-and-tube vaporizers, hot water heaters, enhanced boil off system, controls replacement, and new electric service.

2018 EPCOR, Ontario
Oversight of a system integrity study including development of digital capacity model, bottleneck identification, capital cost estimating and strategic planning.

2018 Woodard & Curran/GEO Environmental, Tewksbury, MA
Design and permitting of an elevated pressure gas service in Massachusetts, materials selection audit, detailed design, testing, MA state permitting.

2-STAFF-29

Reference: **Exhibit 2 / Tab 3 / Schedule 2/ Pgs. 12-13**

Request:

The system integrity study indicates that the initial run of the GASWorkS model showed poor results when compared to historical records and anecdotal testimonies of real-world pressure throughout the system. In order to correct for these errors, Cornerstone made certain adjustments to the GASWorkS model. One of the adjustments was to exclude the delivery of gas from the local wells.

Please explain why this adjustment was made considering that one of the objectives of the study would be to measure the system pressure without supply from local wells and to measure the pressure again but this time including supply from local wells. This would confirm whether system pressure is low when gas is not received from local wells and also confirm the impact of local volumes on system pressure.

Response:

Despite the original modeling objective of confirming the impact of these local volumes on system pressure, these local well supplies represent a small percentage of the total overall gas supply at peak demand (i.e., 1.4%). As such, the impact of the local well supplies are sensitive to the other assumptions used in the model, making it difficult to measure the impact of these supplies through the modeling exercise. It is known, however, that these supplies do enter the system at a low pressure area and therefore contribute to meeting the peak day requirements.

Given the relatively small volumes the local production represents, the fact that the supplies in these wells are declining, and the contract for this local production ends in 2020, it was not appropriate to spend considerable effort to resolve the pressure inconsistencies that the local supply provided in the GASWorkS model. Accordingly, an adjustment was made to remove the delivery of gas from these wells in order to assist in correcting the model errors. Further, correcting the model errors allowed Cornerstone to focus efforts on evaluating the impact of the longer-term options to addressing the system integrity issues in order to confirm the Lakeview supply will both resolve the low pressure problem in this region and contribute to meeting the broader system growth requirements.

2-STAFF-30

Reference: **Exhibit 2 / Tab 3 / Schedule 2/ Pg.15**

Request:

Cornerstone believes that the undersized fittings and incorrectly sized valves littered throughout the system contribute to the error between the southern pressures in the calibrated model and what the system has experienced according to recorded data and operations personnel. Regardless of whatever discrepancies exist between modelling numbers and real world pressure, it is universally agreed upon that the southern area of the system is in need of reinforcement.

(a) Please explain what "universally agreed upon" means.

(b) How reliable are the Cornerstone results considering the discrepancies between modelling numbers and real world pressure?

(c) What additional value does the hydraulic modelling provide considering that Cornerstone has relied on the universally agreed view that the southern area of the system needs reinforcement?

Response:

(a) The term "universally agreed upon" as used in the System Integrity Study was intended to mean as agreed upon by the team involved in the study comprised of both Cornerstone and ENGLP operating personnel with direct experience in observing low pressures during peak period.

(b) While there continues to be some discrepancies between the hydraulic modelling and the observed pressures, ENGLP is seeking out these potential restrictions in the system that could be causing the discrepancies. Hydraulic modeling continues to be of value to help pinpoint the potential areas of the restrictions. These discrepancies however do not change the conclusion that these two reinforcement projects are required at this time.

(c) Operating staff observed low pressures in the system suggesting that some reinforcement would be required to alleviate the low pressure problem. Hydraulic modelling is necessary to characterize how the system operates under current load conditions. Once the system is characterized, load growth projections can be added to the existing demands. Various alternatives can then be evaluated to determine the solutions that offer the best combination of cost effectiveness and reliability to both alleviate the low pressure conditions and meet future growth requirements.

2-STAFF-31

Reference: **Exhibit 2 / Tab 3 / Schedule 2/ Pg.16**

Request:

The system integrity study notes that once a calibrated model was created, Cornerstone evaluated the system's capabilities to account for growth and expansion through the year 2024. Cornerstone developed a gas load for each town/village up to the year 2024.

In a footnote, Cornerstone has noted that it has assumed a higher growth rate of 5% for Belmont but has used 2.5% for the model as the growth is mostly new construction with added efficiencies. For all other areas, the growth rate is 2%.

(a) Please indicate what portion of the growth rate in other areas is likely to be new construction with added efficiencies? Has any adjustment been made to the other growth areas?

(b) If the growth in other areas is mostly new construction (>75%) and no corresponding adjustment has been made, please recalibrate the model and adjust the 2024 gas load.

Response:

(a) ENGLP does not have the analysis to provide a reliable estimate of the portion of growth in other areas that is likely to be new construction with added efficiencies. No adjustment was made to the growth rate for other areas.

(b) Cornerstone has indicated that reducing the growth rate by half for all other areas would have an insignificant impact on the 2024 gas load and the outcome or recommendations of the study would not change. In addition, ENGLP notes that the recommended capital projects are required to address ENGLP's system integrity issues existing at current demands. In January 2019, the system experienced record peak demands which lead to extremely low pressures in the system, with pressures dipping lower than 5 psi in some areas in the southern part of the system.

2-STAFF-32
Reference: **Exhibit 2 / Tab 3 / Schedule 2/ Pg.18**

Request:

In its report, Cornerstone considered a number of infrastructure improvement projects to address low pressure concerns in southern and southeastern part of the EPCOR distribution system. One of the options (Project 6) talks about the possibility of taking gas from an existing compressor station on Gully Road off of Nova Scotia Line and injecting the gas into the 4 inch pipe along Nova Scotia Line.

(a) Please confirm if EPCOR owns or operates a natural gas compressor within its distribution system.

(b) How many compressor stations does EPCOR operate in its franchise area?

(c) Compressor station was not identified as an asset category in the USP. If EPCOR does own/operate compressor stations, please provide the relevant details (rate base, number of units, type, horsepower, asset condition, replacement cycle, maintenance costs etc.)

Response:

(a) ENGLP Aylmer does not own nor operate a natural gas compressor within its distribution system or franchise area. The natural gas compressor station referenced, and associated wells, is the local production owned by a third-party as part of the Lakeview Reinforcement Project in the USP.

(b) See ENGLP's response to (a) above.

(c) See ENGLP's response to (a) above.

2-STAFF-33

Reference: **Exhibit 2 / Tab 3 / Schedule 2/ Pg.20**

Request:

In Cornerstone's view, what is shown in CAD records and other piping records do not match the actual physical assets. Consequently, Cornerstone has advised EPCOR to increase their efforts in investigating and resolving some of the choke points and has recommended a series of tasks to create an accurate record of piping facilities.

(a) Has the management of EPCOR discussed the recommendations of Cornerstone? If yes, please provide details.

(b) Does EPCOR intend to implement the suggested recommendations? If yes, please indicate which recommendations will be implemented, their costs and the timeline of implementing the recommendations.

(c) Cornerstone has referred to resolving some of the choke points. Has Cornerstone or EPCOR evaluated the cost and benefits of resolving the choke points, and its impact on system pressure? If yes, please provide details including cost estimates. If no, please provide reasons.

Response:

(a) ENGLP management and operating staff were engaged throughout the study, and discussed the investigation methodology and findings as Cornerstone's study progressed. Cornerstone reviewed and discussed their conclusions and recommendations with ENGLP management to ensure it's understanding of the findings and recommendations, and to explore all potential options.

(b) As noted in System Integrity Study, Exhibit 2, Tab 3, Schedule 2 page 14, the utility has been addressing choke points when found over time, and ENGLP plans to continue to investigate and address these restrictions. Based on discussions with Cornerstone, investigating and resolving additional choke points is likely to result in small, incremental improvements to system pressures in some localized areas. Accordingly, ENGLP plans to investigate choke points over time using existing utility resources through the normal course of operations and maintenance. Based on this planned approach, no additional OM&A costs or capital expenditures to address the choke points were forecasted in the Test period.

(c) Modelling and evaluating the impact on pressure of the various choke points would be a significant undertaking and cost. Given the understanding that the impact to the system would be minimal and localized, ENGLP did not feel it prudent to proceed with further analysis. While a formal analysis of the cost/benefit associated with addressing various choke points was not completed, the distribution system modeling exercise, and subsequent review and discussions, have assisted in identifying areas where addressing the choke points would provide most benefit. This will allow ENGLP to focus future efforts to these areas.

3-STAFF-34

Reference: **Exhibit 3 / Tab 1 / Schedule 1/ Tables 3.1-1 to 3.1-9**

Request:

For ables 3.1-1 to 3.1-9, the 2018 column is referred to as "Forecast".

Please update the tables with actuals for 2018 and compare the accuracy of the forecast.

Response:

ENGLP's Application in this proceeding used actual consumption figures from January – August, and a forecast for September – December for 2018. Tables 3.1-1 through 3.1-9 have been updated to include 2018 actuals, as well as a comparison of actuals to forecast.

3-STAFF-34-1
Table 3.1-1 Updated
Summary - Distribution Revenue Under Current Distribution Rates
($)

	Rate Class	A **2018 Actuals**	B **2018 Forecast**	C **2019 Bridge**	D **2020 Test**	E **2018 Actuals - Forecast**	F **2018 % Difference (Col. E / Col. B)**
1	Rate 1 - Residential	4,237,075	4,120,249	4,393,645	4,364,807	116,826	2.8%
2	Rate 1 - Commercial	809,973	759,482	761,569	747,422	50,491	6.6%
3	Rate 1 - Industrial	246,766	239,820	235,380	228,587	6,947	2.9%
4	Rate 2	190,716	167,257	170,709	159,418	23,459	14.0%
5	Rate 3	170,827	176,125	183,781	173,856	(5,297)	-3.0%
6	Rate 4	133,854	125,020	138,256	137,288	8,834	7.1%
7	Rate 5	53,736	57,215	61,999	60,012	(3,479)	-6.1%
8	Rate 6	1,743,781	1,589,704	1,133,887	1,133,887	154,076	9.7%
9	**Total Revenue**	**7,586,729**	**7,234,872**	**7,079,226**	**7,005,277**	**351,857**	**4.9%**

Table 3-STAFF-34-1 (Table 3.1-1) shows that the 2018 Actuals resulted in 4.9% more revenue than originally forecast.

3-STAFF-34-2
Table 3.1-2 Updated
R1- Residential

		A 2018 Actuals	B 2018 Forecast	C 2019 Bridge	D 2020 Test	E 2018 Actuals - Forecast
1	**Billing Parameters**					
2	Connections	8,364	8,363	8,617	8,878	1
3	**Volume (m3's)**					
4	Tier 1 (First 1,000 m3 / mo.)	17,421,988	16,726,306	16,451,799	16,937,809	695,682
5	Tier 2 (Over 1,000 m3 / mo.)	149,123	110,051	104,704	107,788	39,072
6	**Rates**					
7	Fixed Monthly Rate	13.50	13.50	15.50	15.50	
8	Tier 1 Rate (first 1,000 m3's)	16.2312	16.2312	15.9486	15.9486	
9	Tier 2 Rate (> 1,000 m3's)	10.9099	10.9099	11.3519	11.3519	
10	**Revenue***					
11	Fixed Monthly Rate	1,405,152	1,405,058	1,602,739	1,651,227	94
12	Tier 1 Rate (first 1,000 m3's)	2,815,489	2,703,063	2,623,832	2,701,343	112,426
13	Tier 2 Rate (> 1,000 m3's)	16,434	12,128	11,886	12,236	4,306
14	**Total Revenue**	**4,237,075**	**4,120,249**	**4,238,456**	**4,364,807**	**116,826**
15	IRM Rebalancing Rider			155,189		
16	Distribution Revenue Including IRM Rebalancing Rider	4,237,075	4,120,249	4,393,645	4,364,807	116,826

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-3
Table 3.1-3 Updated
R1 – Commercial

		A 2018 Actuals	B 2018 Forecast	C 2019 Bridge	D 2020 Test	E 2018 Actuals - Forecast
1	**Billing Parameters**					
2	Connections	477	477	485	494	0
3	**Volume (m3's)**					
4	Tier 1 (First 1,000 m3 / mo.)	2,475,428	2,366,759	2,240,849	2,279,405	108,669
5	Tier 2 (Over 1,000 m3 / mo.)	2,992,579	2,694,120	2,528,420	2,572,300	298,459
6	**Rates**					
7	Fixed Monthly Rate	13.50	13.50	15.50	15.50	
8	Tier 1 Rate (first 1,000 m3's)	16.2312	16.2312	15.9486	15.9486	
9	Tier 2 Rate (> 1,000 m3's)	10.9099	10.9099	11.3519	11.3519	
10	**Revenue***					
11	Fixed Monthly Rate	80,136	80,098	90,261	91,884	38
12	Tier 1 Rate (first 1,000 m3's)	400,043	382,481	357,384	363,533	17,562
13	Tier 2 Rate (> 1,000 m3's)	329,794	296,903	287,024	292,005	32,891
14	**Total Revenue**	**809,973**	**759,482**	**734,668**	**747,422**	**50,491**
15	IRM Rebalancing Rider			26,901		
16	Distribution Revenue Including IRM Rebalancing Rider	809,973	759,482	761,569	747,422	50,491

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-4
Table 3.1-4 Updated
R1 – Industrial

		A **2018 Actuals**	B **2018 Forecast**	C **2019 Bridge**	D **2020 Test**	E **2018 Actuals - Forecast**
1	**Billing Parameters**					
2	Connections	67	67	67	68	0
3	**Volume (m3's)**					
4	Tier 1 (First 1,000 m3 / mo.)	410,997	430,916	390,053	392,687	(19,919)
5	Tier 2 (Over 1,000 m3 / mo.)	1,534,346	1,442,737	1,341,669	1,350,528	91,608
6	**Rates**					
7	Fixed Monthly Rate	13.50	13.50	15.50	15.50	
8	Tier 1 Rate (first 1,000 m3's)	16.2312	16.2312	15.9486	15.9486	
9	Tier 2 Rate (> 1,000 m3's)	10.9099	10.9099	11.3519	11.3519	
10	**Revenue***					
11	Fixed Monthly Rate	11,256	11,186	12,553	12,648	70
12	Tier 1 Rate (first 1,000 m3's)	66,419	69,638	62,208	62,628	(3,219)
13	Tier 2 Rate (> 1,000 m3's)	169,091	158,995	152,305	153,311	10,096
14	**Total Revenue**	**246,766**	**239,820**	**227,066**	**228,587**	**6,947**
15	IRM Rebalancing Rider			8,314		
16	Distribution Revenue Including IRM Rebalancing Rider	246,766	239,820	235,380	228,587	6,947

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-5
Table 3.1-5 Updated
Rate 2

		A **2018 Actuals**	B **2018 Forecast**	C **2019 Bridge**	D **2020 Test**	E **Actuals - Forecast 2018**
1	**Billing Parameters**					
2	Connections	53	53	52	50	0
3	**Volume (m3's)**					
4	April - October					
5	Tier 1 (First 1,000 m3 / mo.)	91,840	90,336	88,065	85,252	1,503
6	Tier 2 (Next 24,000 m3 / mo.)	753,712	743,346	735,595	712,097	10,367
7	Tier 3 (Over 25,000 m3 / mo.)	178,611	173,721	140,529	136,040	4,890
8	November - March					
9	Tier 1 (First 1,000 m3 / mo.)	77,182	59,372	68,343	66,160	17,809
10	Tier 2 (Next 24,000 m3 / mo.)	394,565	283,790	272,145	263,451	110,775
11	Tier 3 (Over 25,000 m3 / mo.)	37,389	31,380	17,988	17,414	6,010
12	**Rates**					
13	Fixed Monthly Rate	15.00	15.00	17.25	17.25	
14	April - October					
15	Tier 1 (First 1,000 m3 / mo.)	15.8212	15.8212	17.2765	17.2765	
16	Tier 2 (Next 24,000 m3 / mo.)	9.4826	9.4826	9.4826	9.4826	
17	Tier 3 (Over 25,000 m3 / mo.)	6.1698	6.1698	6.1698	6.1698	
18	November - March					
19	Tier 1 (First 1,000 m3 / mo.)	19.9424	19.9424	21.7767	21.7767	
20	Tier 2 (Next 24,000 m3 / mo.)	15.6960	15.6960	15.6960	15.6960	
21	Tier 3 (Over 25,000 m3 / mo.)	15.2899	15.2899	15.2899	15.2899	
22	**Revenue***					
23	Fixed Monthly Rate	9,898	9,953	10,692	10,350	-55
24	April - October					
25	Tier 1 (First 1,000 m3 / mo.)	14,721	14,480	15,215	14,729	241
26	Tier 2 (Next 24,000 m3 / mo.)	71,472	70,488	69,754	67,525	983
27	Tier 3 (Over 25,000 m3 / mo.)	11,020	10,718	8,670	8,393	302
28	November - March					
29	Tier 1 (First 1,000 m3 / mo.)	15,958	12,276	14,883	14,407	3,682
30	Tier 2 (Next 24,000 m3 / mo.)	61,931	44,544	42,716	41,351	17,387
31	Tier 3 (Over 25,000 m3 / mo.)	5,717	4,798	2,750	2,663	919
32	**Total Revenue**	**190,716**	**167,257**	**164,679**	**159,418**	**23,459**
33	IRM Rebalancing Rider			6,030		
34	Distribution Revenue Including IRM Rebalancing Rider	190,716	167,257	170,709	159,418	23,459

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-6
Table 3.1-6 Updated
Rate 3

		A **2018** **Actuals**	B **2018** **Forecast**	C **2019** **Bridge**	D **2020** **Test**	E **2018** **Actuals -** **Forecast**
1	**Billing Parameters**					
2	Connections	6	6	6	6	0
3	Firm Demand	299,631	299,631	299,631	299,631	0
4	Firm Delivery (volume - m3's)	1,764,644	1,893,687	1,801,305	1,721,684	-129,043
5	**Rates**					
6	Fixed Monthly Rate	150.00	150.00	172.50	172.50	
7	Firm Demand	29.0974	29.0974	29.0974	29.0974	
8	Firm Delivery	4.0357	4.0357	4.3127	4.3127	
9	**Revenue***					
10	Fixed Monthly Rate	11,205	11,205	12,420	12,420	0
11	Firm Demand	87,185	87,185	87,185	87,185	0
12	Firm Delivery	72,438	77,735	77,685	74,251	-5,297
13	**Total Revenue**	**170,827**	**176,125**	**177,290**	**173,856**	**-5,297**
14	IRM Rebalancing Rider			6,492		
15	Distribution Revenue Including IRM Rebalancing Rider	170,827	176,125	183,781	173,856	-5,297

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-7
Table 3.1-7 Updated
Rate 4

		A **2018 Actuals**	B **2018 Forecast**	C **2019 Bridge**	D **2020 Test**	E **2018 Actuals - Forecast**
1	**Billing Parameters**					
2	Connections	36	36	37	38	0
3	**Volumes (m3's)**					
4	April - December					
5	Block 1 (First 1,000 m3 / mo.)	80,914	94,084	91,612	94,302	(13,170)
6	Block 2 (Over 1,000 m3 / mo.)	1,042,615	942,313	1,003,585	1,033,055	100,302
7	January - March					
8	Block 1 (First 1,000 m3 / mo.)	16,523	14,892	17,490	18,003	1,632
9	Block 2 (Over 1,000 m3 / mo.)	5,559	5,010	3,541	3,645	549
10	**Rates**					
11	Fixed Monthly Rate	15.0000	15.0000	17.2500	17.2500	
12	April - December					
13	Block 1 (First 1,000 m3 / mo.)	15.8149	15.8149	17.1487	17.1487	
14	Block 2 (Over 1,000 m3 / mo.)	10.5218	10.5218	10.5218	10.5218	
15	January - March					
16	Block 1 (First 1,000 m3 / mo.)	20.1755	20.1755	21.8770	21.8770	
17	Block 2 (Over 1,000 m3 / mo.)	16.9052	16.9052	16.9052	16.9052	
18	**Revenue***					
19	Fixed Monthly Rate	6,723	6,723	7,642	7,866	0
20	April - December					
21	Block 1 (First 1,000 m3 / mo.)	13,156	15,298	15,710	16,172	(2,141)
22	Block 2 (Over 1,000 m3 / mo.)	109,702	99,148	105,595	108,696	10,554
23	January - March					
24	Block 1 (First 1,000 m3 / mo.)	3,334	3,004	3,826	3,939	329
25	Block 2 (Over 1,000 m3 / mo.)	940	847	599	616	93
26	**Total Revenue**	**133,854**	**125,020**	**133,372**	**137,288**	**8,834**
27	IRM Rebalancing Rider			4,884		
28	Distribution Revenue Including IRM Rebalancing Rider	133,854	125,020	138,256	137,288	8,834

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-8
Table 3.1-8 Updated
Rate 5

		A 2018 Actuals	B 2018 Forecast	C 2019 Bridge	D 2020 Test	E 2018 Actuals - Forecast
1	**Billing Parameters**					
2	Connections	4	4	4	4	0
3	Firm Delivery (volume - m3's)	626,165	673,249	685,748	685,748	(47,084)
4	**Rates**					
5	Fixed Monthly Rate	150.00	150.00	172.50	172.50	
6	Firm Delivery	7.38875	7.38875	7.54391	7.54391	
7	**Revenue***					
8	Fixed Monthly Rate	7,470	7,470	8,077	8,280	0
9	Firm Delivery	46,266	49,745	51,732	51,732	(3,479)
10	**Total Revenue**	**53,736**	**57,215**	**59,809**	**60,012**	**(3,479)**
11	IRM Rebalancing Rider			2,190		
12	Distribution Revenue Including IRM Rebalancing Rider	53,736	57,215	61,999	60,012	(3,479)

* 2018 revenues assume rates from EB-2018-0235 effective October 1, 2018.

3-STAFF-34-9
Table 3.1-9 Updated
Rate 6

		A **Actuals Jan – Sept 2018**	B **Actuals Oct – Dec 2018**	C **Actuals Jan – Dec 2018**	D **2018 Forecast**	E **2019 Bridge**	F **2020 Test**	G **2018 Actuals - Forecast**
1	**Billing Parameters**							
2	Connections	1	1	1	1	1	1	0
3	Firm Delivery (volume - m3's)	26,451,687	15,880,636	42,332,323	40,374,973	59,243,876	59,243,876	1,957,350
4	Firm Demand	1,808,181	626,400	2,434,581	2,055,870	2,505,600	2,505,600	378,711
5	**Rates**							
6	Fixed Monthly Rate	150.00	124,323.96			94,490.62	94,490.62	
7	Firm Delivery	3.8894						
8	Firm Demand	18.8392						
9	**Revenue**							
10	Fixed Monthly Rate	1,350	372,972	374,322	374,322	1,133,887	1,133,887	0
11	Firm Delivery	1,028,812		1,028,812	946,082			82,730
12	Firm Demand	340,647		340,647	269,301			71,346
13	**Total**	**1,370,809**	**372,972**	**1,743,781**	**1,589,704**	**1,133,887**	**1,133,887**	**154,076**

3-STAFF-35
Reference: **Exhibit 3 / Tab 1 / Schedule 1/ Tables 3.2-1 to 3.2-12**

Request:

For all the above referenced tables, please update the Jan – Dec 2018 Forecast with actuals.

Response:

Tables 3.2-1 through 3.2-12 have been updated to include actuals for 2018 below.

3-STAFF-35-1
Table 3.2-1 (Updated)
OEB Approved Volumes
(m3's)

	Rate Year Year	A Oct - Sept 2011	B Oct - Sept 2012	C Oct - Sept 2013	D Oct - Sept 2014	E Oct - Sept 2015	F Oct - Sept 2016	G Oct - Sept 2017	H Oct - Sept 2018	I Actuals Jan - Dec 2018	J Bridge Jan - Dec 2019	K Test Jan - Dec 2020
1	Rate 1 - Residential	13,103,581	13,103,581	13,103,581	13,103,581	13,103,581	13,103,581	13,103,581	13,103,581	13,103,581	14,699,145	14,699,145
2	Rate 1 - Commercial	4,131,750	4,131,750	4,131,750	4,131,750	4,131,750	4,131,750	4,131,750	4,131,750	4,131,750	4,326,736	4,326,736
3	Rate 1 - Industrial	598,028	598,028	598,028	598,028	598,028	598,028	598,028	598,028	598,028	1,544,914	1,544,914
4	Rate 2	502,860	502,860	502,860	502,860	502,860	502,860	502,860	502,860	502,860	1,454,147	1,454,147
5	Rate 3	2,195,299	2,195,299	2,195,299	2,195,299	2,195,299	2,195,299	2,195,299	2,195,299	2,195,299	1,485,572	1,485,572
6	Rate 4	454,263	454,263	454,263	454,263	454,263	454,263	454,263	454,263	454,263	912,931	912,931
7	Rate 5	947,162	947,162	947,162	947,162	947,162	947,162	947,162	947,162	947,162	553,894	553,894
8	Rate 6	33,416,816	33,416,816	33,416,816	33,416,816	33,416,816	33,416,816	33,416,816	33,416,816	33,416,816	38,423,518	38,423,518
9	**Total**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**55,349,759**	**63,400,857**	**63,400,857**

* No volumes approved for a Jan - Dec 2018 rate year.

3-STAFF-35-2
Table 3.2-2 (Updated)
Actual / Forecast Volumes
(m3's)

		A	B	C	D	E	F	G	H	I	J	K
										Actuals	**Bridge**	**Test**
	Period Year	**Oct - Sept 2011**	**Oct - Sept 2012**	**Oct - Sept 2013**	**Oct - Sept 2014**	**Oct - Sept 2015**	**Oct - Sept 2016**	**Oct - Sept 2017**	**Oct - Sept 2018**	**Jan - Dec 2018**	**Jan - Dec 2019**	**Jan - Dec 2020**
1	Rate 1 - Residential	12,825,392	11,291,854	13,531,207	16,088,024	16,056,272	13,660,975	14,676,393	17,032,346	17,571,111	16,556,503	17,045,597
2	Rate 1 - Commercial	4,052,772	3,362,848	4,122,307	4,829,641	4,694,604	4,029,161	4,313,791	5,246,705	5,468,007	4,769,270	4,851,704
3	Rate 1 - Industrial	1,011,475	1,258,899	1,422,335	1,534,158	1,733,658	1,449,099	1,485,534	1,826,769	1,945,343	1,731,722	1,743,215
4	Rate 2	1,752,028	1,860,244	1,960,797	1,955,809	1,386,920	1,231,709	1,516,589	1,044,491	1,533,298	1,322,652	1,280,400
5	Rate 3	2,516,809	2,319,084	1,636,206	1,794,654	1,750,310	1,530,185	1,642,277	1,662,105	1,764,644	1,801,305	1,721,684
6	Rate 4	234,604	491,946	710,719	903,963	1,427,690	865,109	910,102	1,095,301	1,145,610	1,116,228	1,149,006
7	Rate 5	695,814	1,123,128	904,722	990,935	1,181,585	632,393	565,347	737,991	626,165	685,748	685,748
8	Rate 6	30,577,936	31,721,406	31,357,510	31,527,596	33,955,603	38,700,863	38,528,525	33,739,752	42,332,323	66,699,025	66,699,025
9	**Total**	**53,666,830**	**53,429,409**	**55,645,803**	**59,624,780**	**62,186,642**	**62,099,494**	**63,638,559**	**62,385,461**	**72,386,501**	**94,682,453**	**95,176,378**

3-STAFF-35-3
Table 3.2-3 (Updated)
Normalized Volumes
(m3's)

		A	B	C	D	E	F	G	H	I	J	K
										Actuals	**Bridge**	**Test**
	Period Year	**Oct - Sept 2011**	**Oct - Sept 2012**	**Oct - Sept 2013**	**Oct - Sept 2014**	**Oct - Sept 2015**	**Oct - Sept 2016**	**Oct - Sept 2017**	**Oct - Sept 2018**	**Jan - Dec 2018**	**Jan - Dec 2019**	**Jan - Dec 2020**
1	Rate 1 - Residential	12,356,951	12,730,133	13,694,535	14,627,615	15,082,669	14,657,722	15,722,811	16,824,343	17,313,830	16,556,503	17,045,597
2	Rate 1 - Commercial	3,920,434	3,803,776	4,170,301	4,366,332	4,388,268	4,338,322	4,651,850	5,191,706	5,300,972	4,769,270	4,851,704
3	Rate 1 - Industrial	1,005,051	1,394,013	1,421,020	1,427,189	1,641,773	1,615,395	1,597,511	1,909,607	1,859,241	1,731,722	1,743,215
4	Rate 2	1,752,028	1,860,244	1,960,797	1,955,809	1,386,920	1,231,709	1,516,589	1,390,897	1,533,298	1,322,652	1,280,400
5	Rate 3	2,589,948	2,150,725	1,881,029	1,693,664	1,553,668	1,443,894	1,368,297	1,900,603	1,749,836	1,801,305	1,721,684
6	Rate 4	234,604	491,946	710,719	903,963	1,427,690	865,109	910,102	1,127,637	1,145,610	1,116,228	1,149,006
7	Rate 5	695,814	1,123,128	904,722	990,935	1,181,585	632,393	565,347	733,512	626,165	685,748	685,748
8	Rate 6	30,577,936	31,721,406	31,357,510	31,527,596	33,955,603	38,700,863	38,528,525	33,687,861	42,332,323	66,699,025	66,699,025
9	**Total**	**53,132,766**	**55,275,371**	**56,100,634**	**57,493,103**	**60,618,177**	**63,485,408**	**64,861,032**	**62,766,165**	**71,861,277**	**94,682,453**	**95,176,378**

3-ST4FF-35-4
Table 3.2-4 (Updated)
OEB Approved Connections

		A	B	C	D	E	F	G	H	I	J	K
	Rate Year Year	**Oct - Sept 2011**	**Oct - Sept 2012**	**Oct - Sept 2013**	**Oct - Sept 2014**	**Oct - Sept 2015**	**Oct - Sept 2016**	**Oct - Sept 2017**	**Oct - Sept 2018**	**Actuals Jan - Dec 2018**	**Bridge Jan - Dec 2019**	**Test Jan - Dec 2020**
1	Rate 1 - Residential	6,560	6,560	6,560	6,560	6,560	6,560	6,560	6,560	6,560	8,148	
2	Rate 1 - Commercial	414	414	414	414	414	414	414	414	414	462	
3	Rate 1 - Industrial	42	42	42	42	42	42	42	42	42	66	
4	Rate 2	73	73	73	73	73	73	73	73	73	53	
5	Rate 3	4	4	4	4	4	4	4	4	4	5	
6	Rate 4	23	23	23	23	23	23	23	23	23	36	
7	Rate 5	5	5	5	5	5	5	5	5	5	4	
8	Rate 6	1	1	1	1	1	1	1	1	1	1	
9	**Total**	**7,122**	**7,122**	**7,122**	**7,122**	**7,122**	**7,122**	**7,122**	**7,122**	**7,122**	**8,775**	**0**

* No connections approved for a Jan - Dec 2018 rate year.

3-STAFF-35-5
Table 3.2-5 (Updated)
Actual & Forecasted Average Connections

		A	B	C	D	E	F	G	H	I	J	K
										Actual	**Bridge**	**Test**
	Period	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Jan - Dec**	**Jan - Dec**	**Jan - Dec**
	Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2018**	**2019**	**2020**
1	Rate 1 - Residential	6,568	6,810	7,112	7,398	7,670	7,897	8,073	8,313	8,364	8,617	8,878
2	Rate 1 - Commercial	404	411	422	435	443	450	459	474	477	485	494
3	Rate 1 - Industrial	41	50	56	62	63	64	66	67	67	67	68
4	Rate 2	64	67	65	65	63	60	56	53	53	52	50
5	Rate 3	4	4	4	4	4	4	4	6	6	6	6
6	Rate 4	23	23	31	33	34	35	36	36	36	37	38
7	Rate 5	5	5	5	5	5	5	5	4	4	4	4
8	Rate 6	1	1	1	1	1	1	1	1	1	1	1
9	**Total**	**7,110**	**7,370**	**7,696**	**8,003**	**8,284**	**8,516**	**8,699**	**8,954**	**9,007**	**9,269**	**9,539**

3-STAFF-35-6
Table 3.2-6 (Updated)
Actual & Forecasted Year End Connections

		A	B	C	D	E	F	G	H	I	J	K
										Actual	**Bridge**	**Test**
	Period	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Jan - Dec**	**Jan - Dec**	**Jan - Dec**
	Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2018**	**2019**	**2020**
1	Rate 1 - Residential	6,625	6,915	7,216	7,502	7,735	7,993	8,148	8,390	8,419	8,747	9,011
2	Rate 1 - Commercial	401	416	422	437	444	453	462	477	478	490	498
3	Rate 1 - Industrial	43	51	59	63	61	66	66	67	67	68	69
4	Rate 2	68	67	65	65	62	62	53	54	55	51	49
5	Rate 3	4	4	4	4	4	4	5	6	6	6	6
6	Rate 4	22	28	32	33	34	36	36	36	36	37	38
7	Rate 5	5	5	5	5	5	5	4	4	4	4	4
8	Rate 6	1	1	1	1	1	1	1	1	1	1	1
9	**Total**	**7,169**	**7,487**	**7,804**	**8,110**	**8,346**	**8,620**	**8,775**	**9,035**	**9,066**	**9,403**	**9,677**

3-STAFF-35-7
Table 3.2-7 (Updated)
OEB Approved Revenues
($)

	Rate Year Year	A Oct - Sept 2011	B Oct - Sept 2012	C Oct - Sept 2013	D Oct - Sept 2014	E Oct - Sept 2015	F Oct - Sept 2016	G Oct - Sept 2017	H Oct - Sept 2018	I Actuals Jan - Dec 2018	J Bridge Jan - Dec 2019	K Test Jan - Dec 2020
1	Rate 1 - Residential	3,049,854	3,049,854	3,071,919	3,082,753	3,118,766	3,155,284	3,155,284	3,155,284		3,982,517	3,827,328
2	Rate 1 - Commercial	589,395	589,395	594,397	596,852	604,874	613,002	613,002	613,002		690,299	663,398
3	Rate 1 - Industrial	76,381	76,381	76,992	77,292	78,261	79,241	79,241	79,241		212,096	203,782
4	Rate 2	69,658	69,658	70,201	70,468	71,312	72,167	72,167	72,167		188,760	182,730
5	Rate 3	165,397	165,397	166,687	167,322	169,321	171,352	171,352	171,352		146,837	140,345
6	Rate 4	62,517	62,517	63,004	63,244	64,001	64,769	64,769	64,769		157,998	153,114
7	Rate 5	74,840	74,840	75,424	75,710	76,615	77,534	77,534	77,534		51,384	49,194
8	Rate 6	1,492,305	1,492,305	1,503,945	1,509,652	1,527,768	1,546,089	1,546,089	1,546,089		1,133,887	1,133,887
9	**Total**	**5,580,347**	**5,580,347**	**5,622,569**	**5,643,293**	**5,710,918**	**5,779,438**	**5,779,438**	**5,779,438**		**6,563,778**	**6,353,778**

3-STAFF-35-8
Table 3.2-8 (Updated)
Historic Revenues
($)

		A	B	C	D	E	F	G	H	I	J	K
	Period Year	**Oct - Sept 2011**	**Oct - Sept 2012**	**Oct - Sept 2013**	**Oct - Sept 2014**	**Oct - Sept 2015**	**Oct - Sept 2016**	**Oct - Sept 2017**	**Oct - Sept 2018**	**Actuals Jan - Dec 2018**	**Bridge* Jan - Dec 2019**	**Test Jan - Dec 2020**
1	Rate 1 - Residential	3,002,868	2,820,249	3,225,422	3,682,808	3,726,738	3,487,504	3,728,013	4,110,455	4,237,075	4,393,645	4,364,807
2	Rate 1 - Commercial	609,191	503,215	598,145	689,328	674,450	609,914	656,041	782,201	809,973	761,569	747,422
3	Rate 1 - Industrial	122,916	154,018	173,061	189,762	212,091	185,393	211,528	236,324	246,766	235,380	228,587
4	Rate 2	244,327	186,521	209,653	212,008	162,092	142,379	195,210	163,335	190,716	170,708	159,417
5	Rate 3	164,834	160,171	135,002	141,651	140,306	134,602	127,767	145,357	170,828	183,781	173,856
6	Rate 4	38,355	58,488	84,860	107,298	167,515	102,848	91,607	129,821	133,854	138,256	137,288
7	Rate 5	57,212	89,534	73,570	80,311	91,724	55,931	47,871	60,332	53,736	61,999	60,012
8	Rate 6	1,478,179	1,485,545	1,491,329	1,499,258	1,531,844	1,783,621	1,797,592	1,659,021	1,743,781	1,133,887	1,133,887
9	**Total**	**5,717,882**	**5,457,741**	**5,991,042**	**6,602,424**	**6,706,760**	**6,502,192**	**6,855,629**	**7,286,845**	**7,586,729**	**7,079,226**	**7,005,276**

* Includes rebalancing rate rider in 2019.

3-STAFF-35-9
Table 3.2-9 (Updated)
Historic Revenues - Normalized
($)

		A	B	C	D	E	F	G	H	I	J	K
										Actual	**Bridge***	**Test**
	Period	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Jan - Dec**	**Jan - Dec**	**Jan - Dec**
	Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2018**	**2019**	**2020**
1	Rate 1 - Residential	2,946,924	3,059,702	3,280,512	3,484,366	3,608,590	3,653,317	3,854,306	4,071,646	4,197,403	4,393,645	4,364,807
2	Rate 1 - Commercial	562,738	551,692	605,483	635,409	641,518	651,686	694,847	769,375	792,062	761,569	747,422
3	Rate 1 - Industrial	122,913	169,990	175,540	177,925	203,936	205,615	203,830	241,633	238,922	235,380	228,587
4	Rate 2	244,327	186,521	209,653	212,008	162,092	142,379	195,210	163,335	190,716	170,708	159,417
5	Rate 3	171,339	155,791	146,745	140,071	135,069	133,100	130,199	154,981	170,827	183,781	173,856
6	Rate 4	38,355	58,488	84,860	107,298	167,515	102,848	91,607	129,821	133,854	138,256	137,288
7	Rate 5	57,212	89,534	73,570	80,311	91,724	55,931	47,871	60,332	53,736	61,999	60,012
8	Rate 6	1,478,179	1,485,545	1,491,329	1,499,258	1,531,844	1,783,621	1,797,592	1,659,021	1,743,781	1,133,887	1,133,887
9	**Total**	**5,621,986**	**5,757,264**	**6,067,691**	**6,336,645**	**6,542,288**	**6,728,496**	**7,015,462**	**7,250,143**	**7,521,301**	**7,079,226**	**7,005,276**

* Includes rebalancing rate rider in 2019.

3-STAFF-35-10
Table 3.2-10 (Updated)
Historical OEB-approved vs Historical Actual

		A	B	C	D	E	F	G	H	I	J	K
	Period Year	**Oct - Sept 2011**	**Oct - Sept 2012**	**Oct - Sept 2013**	**Oct - Sept 2014**	**Oct - Sept 2015**	**Oct - Sept 2016**	**Oct - Sept 2017**	**Oct - Sept 2018**	**Actual* Jan - Dec 2018**	**Bridge** Jan - Dec 2019**	**Test Jan - Dec 2020**
1	Volumes (m3's)											
2	Actuals	53,666,830	53,429,409	55,645,803	59,624,780	62,186,642	62,099,494	63,638,559	62,385,461	72,386,502	94,682,453	95,176,378
3	Historical Approved	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759		63,400,857	
4	Difference	(1,682,929)	(1,920,350)	296,044	4,275,021	6,836,883	6,749,735	8,288,800	7,035,702		31,281,596	
5	Revenues ($'s)											
6	Actuals	5,717,882	5,457,741	5,991,042	6,602,424	6,706,760	6,502,192	6,855,629	7,286,845	7,586,729	7,079,226	7,005,276
7	Historical Approved	5,580,347	5,580,347	5,622,569	5,643,293	5,710,918	5,779,438	5,779,438	5,779,438		6,563,778	
8	Difference	137,535	(122,606)	368,473	959,131	995,842	722,754	1,076,191	1,507,407		515,448	
9	Connections (#'s)											
10	Actuals	7,110	7,370	7,696	8,003	8,284	8,516	8,699	8,954	9,007	9,269	9,539
11	Historical Approved	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122		8,775	
12	Difference	**(12)**	**248**	**573**	**881**	**1,162**	**1,394**	**1,577**	**1,832**		**494**	

*No OEB approved values exist for a Jan – Dec 2018 rate year.
**includes rebalancing rate rider in 2019.

3-STAFF-35-11
Table 3.2-11 (Updated)
Historical OEB-approved vs Normalized Historical Actual

		A	B	C	D	E	F	G	H	I	J	K
										Actual*	**Bridge****	**Test**
	Period	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Oct - Sept**	**Jan - Dec**	**Jan - Dec**	**Jan - Dec**
	Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2018**	**2019**	**2020**
1	Volumes (m3's)											
2	Actuals	53,132,766	55,275,371	56,100,634	57,493,103	60,618,177	63,485,408	64,861,032	62,766,165	71,861,277	94,682,453	95,176,378
3	Historical Approved	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759	55,349,759		63,400,857	
4	Difference	(2,216,993)	(74,388)	750,875	2,143,344	5,268,418	8,135,649	9,511,273	7,416,406		31,281,596	
5	Revenues ($'s)											
6	Actuals	5,621,986	5,757,264	6,067,691	6,336,645	6,542,288	6,728,496	7,015,462	7,250,143	7,521,301	7,079,226	7,005,276
7	Historical Approved	5,580,347	5,580,347	5,622,569	5,643,293	5,710,918	5,779,438	5,779,438	5,779,438		6,563,778	
8	Difference	41,639	176,917	445,122	693,352	831,370	949,058	1,236,024	1,470,705		515,448	
9	Connections (#'s)											
10	Actuals	7,110	7,370	7,696	8,003	8,284	8,516	8,699	8,954	9,007	9,269	9,539
11	Historical Approved	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122		8,775	
12	**Difference**	**(12)**	**248**	**573**	**881**	**1,162**	**1,394**	**1,577**	**1,832**		**494**	

*No OEB approved values exist for a Jan – Dec 2018 rate year.
**Includes rebalancing rate rider in 2019.

3-STAFF-35-12
Table 3.2-12 (Updated)
Historical Actual Normalized vs Preceding Year's Historical Actual - Normalized

	Period Year	A Oct - Sept 2011	B Oct - Sept 2012	C Oct - Sept 2013	D Oct - Sept 2014	E Oct - Sept 2015	F Oct - Sept 2016	G Oct - Sept 2017	H Oct - Sept 2018	I Actual* Jan - Dec 2018	J Bridge** Jan - Dec 2019	K Test Jan - Dec 2020
1	Volumes (m3's)											
2	Historical Actual	53,132,766	55,275,371	56,100,634	57,493,103	60,618,177	63,485,408	64,861,032	62,766,165	71,861,277	94,682,453	95,176,378
3	Prior Year Actual		53,132,766	55,275,371	56,100,634	57,493,103	60,618,177	63,485,408	64,861,032		71,861,277	94,682,453
4	Difference		2,142,606	825,262	1,392,470	3,125,074	2,867,231	1,375,624	(2,094,868)		22,821,176	493,926
5	Revenues ($'s)											
6	Historical Actual	5,621,986	5,757,264	6,067,691	6,336,645	6,542,288	6,728,496	7,015,462	7,250,143	7,521,301	7,079,226	7,005,276
7	Prior Year Actual		5,621,986	5,757,264	6,067,691	6,336,645	6,542,288	6,728,496	7,015,462		7,521,301	7,079,226
8	Difference		135,277	310,428	268,954	205,643	186,208	286,966	234,681		(442,075)	(73,950)
9	Connections (#'s)											
10	Actual Connections	7,110	7,370	7,696	8,003	8,284	8,516	8,699	8,954	9,007	9,269	9,539
11	Prior Year Connections		7,110	7,370	7,696	8,003	8,284	8,516	8,699		9,007	9,269
12	**Difference**		**261**	**325**	**307**	**281**	**232**	**183**	**255**		**262**	**270**

*No OEB approved values exist for a Jan – Dec 2018 rate year.
**Includes rebalancing rate rider in 2019.

3-STAFF-36

Reference: **Exhibit 3 / Tab 1 / Schedule 1/ Pg. 21 and Exhibit 1 / Tab 1 / Schedule 1/ Pg.16**

Request:

Table 3.4-1 provides a breakdown of other revenues. Other Revenues for the Bridge Year (2019) and for the Test Year (2020) is the same at $112,913. In the Schedule of Service Charges (Table 1.3.16-1), EPCOR has proposed an increase to the fee structure of all services.

(a) Please explain why Other Revenues for the Test Year are not higher than 2019 considering the proposed increase to the service charges? Are the number of services provided and/or transactions calculated at the proposed rate for 2020?

(b) Please provide a table that uses the same number of forecasted services and/or transactions for 2020 as compared to 2019 and recalculate the 2020 Other Revenues using the proposed service charges.

Response:

(a) The calculation of Other Revenues for 2019 and 2020 did not reflect a bottom-up calculation of price x quantity, but rather a historic average. The 2020 value should have been inflated by the increase in the fees being requested.

(b) Other Revenue has been restated in the Table 3-STAFF-36-1 below based off of 2018 values. The proposed increases to certain charges applies to the Transfer/Connection Charge, Disconnect/Reconnect Charge, Returned Cheques, and Utility Fees. The increase in 2020 relating to the Utility Fees (row 16) reflect the 11% increase to the Utility Fees proposed, but applied to 2019 revenue directly rather than price x quantity. EPCOR proposes to update Other Revenue in its application to reflect these values.

Table 3-STAFF-36-1
Other Revenues

		A **2018 Forecast**	B **2019 Bridge**	C **2020 Test**
1	**Components Impacted by Proposed Increases**			
2	Price			
3	Transfer/Connection Charge	$30.00	$30.00	$35.00
4	Disconnect/Reconnect Charge	$78.00	$78.00	$85.00
5	Returned Cheques	$20.00	$20.00	$48.00
7	Quantity			
8	Transfer/Connection Charge	1,029	1,029	1,029
9	Disconnect/Reconnect Charge	36	36	36
10	Returned Cheques	153	153	153
11	Revenue ($)			
12	Transfer/Connection Charge	30,870	30,870	36,015
13	Disconnect/Reconnect Charge	2,808	2,808	3,060
14	Returned Cheques	3,060	3,060	7,344
15	**Total ($)**	**36,738**	**36,738**	**46,419**
16	Utility Fees	61,028	61,028	67,809
17	Sub-Total of Impacted Components	97,766	97,766	114,228
18	**Components Not Impacted by Proposed Increases**			
19	Late Fees	17,880	17,880	17,880
20	Direct Charge	15,040	15,040	15,040
21	Bank Interest	630	630	630
22	Sub-Total of Non-Impacted Components	33,550	33,550	33,550
23	**Total (row 17 + row 22)**	**131,316**	**131,316**	**147,777**

3-STAFF-37

Reference: **Exhibit 3 / Tab 2 / Schedule 1/ Pg. 6**

Request:

EPCOR has provided a table that summarizes the historic and weather normalized consumption according to the new rate year (January to December calendar year).

(a) Please update the table with 2018 actuals.

(b) The 2020 forecast consumption for R2 seasonal and R3 shows a decline as compared to 2018 and 2019. Please explain the reasons for the forecasted decline in consumption for these two rate classes.

Response:

(a) See Table 3-STAFF-37-1 updated with 2018 Actuals.

Table 3-STAFF-37-1
Historic and Weather Normalized Consumption
(m^3)

		A	B	C	D	E	F	G	H	I
		2013 A	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2017 Normalized**	**2018 A**	**2019 F**	**2020 F**
1	R1 Res	14,287,143	16,127,158	14,948,329	14,417,053	15,400,135	16,015,988	17,571,111	16,556,503	17,045,597
2	R1 Ind	1,436,592	1,666,209	1,430,900	1,462,707	1,752,123	1,860,454	1,945,343	4,769,270	4,851,704
3	R1 Com	4,352,319	4,788,282	4,420,443	4,117,374	4,734,213	4,945,685	5,468,007	1,731,722	1,743,215
4	R2	1,844,495	1,988,124	1,242,867	1,394,132	1,410,653	1,410,653	1,533,298	1,322,652	1,280,400
5	R3	1,644,742	1,792,006	1,692,328	1,492,346	1,653,466	1,712,042	1,764,644	1,801,305	1,721,684
6	R4	861,111	1,345,169	994,710	904,160	1,124,029	1,124,029	1,145,610	1,116,228	1,149,006
7	R5	1,016,630	1,128,958	672,622	562,860	753,900	753,900	626,165	685,748	685,748
8	R6	31,582,423	31,735,774	34,710,609	40,074,176	36,485,139	36,485,139	42,332,323	66,699,025	66,699,025
9	**Total**	**57,025,455**	**60,571,680**	**60,112,808**	**64,424,808**	**63,313,659**	**64,307,890**	**72,386,502**	**94,682,453**	**95,176,378**

(b) R2 Seasonal average consumption per customer is based on a 5-year average of consumption from 2014-2018 which is assumed to not change for the period 2019 to 2020. The decline in total R2 forecast consumption is due to declining customer counts from 2009 to 2018. The number of R2 customers has declined by 3.4% per year, on average, since 2009 and this trend is forecast to continue to 2020.

Average R3 consumption per customer has declined from 616,172 m^3 in 2010 to 294,107 m^3 in 2018. Declining consumption per customer is forecast to continue to 2020. The regression for the R3 class includes a negative time trend variable.

3-STAFF-38

Reference: **Exhibit 3 / Tab 2 / Schedule 1/ Pgs. 7-9**

Request:

The R1 Residential Class consumption forecast is developed using a base load and excess consumption method. EPCOR has used regression to determine the impact of cold weather on average consumption. A time-series regression is used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. EPCOR has indicated that several other variables were examined and found to not show a statistically significant relationship to energy use. Those included economic indicators of full-time employment and GDP, days in each month, work days in each month and a time trend.

(a) Please indicate whether EPCOR examined furnace efficiency and number of persons in household to assess the relationship of these variable to energy use. If the data is available, please update and file the regression model with these two variables.

(b) If EPCOR does not have data regarding furnace efficiency and number of persons in household, will EPCOR be collecting this data in the future as part of its customer engagement survey? If no, why not?

(c) Please confirm whether furnace efficiency is a variable that is commonly used by gas utilities in a regression model.

Response:

(a) EPCOR has not examined furnace efficiency and number of persons in household to assess the relationship of these variables to energy use as that data is not available.

(b) EPCOR will request this data in future customer engagement surveys.

(c) Variables to reflect reduced consumption through efficiency (such as furnace efficiency or, more generally, house vintage) are commonly used in throughput forecast regression models to consider declining per customer usage. This data was not available for the Aylmer service territory. Trend variables, which may capture some of the impact of increased efficiency, were considered but not found to be statistically significant.

3-STAFF-39

Reference: **Exhibit 3 / Tab 2 / Schedule 1/ Pgs. 11-14**

Request:

EPCOR has provided the regression results for the R1 Industrial and Commercial Class and a table showing the accuracy of its forecast using the model coefficients.

(a) Please provide the adjusted R-square of the R1 Industrial regression model.

(b) The mean absolute percentage error is 7.1% for the R1 Industrial class. Did EPCOR consider other methods or variables to reduce the mean absolute percentage error?

(c) The model has under-forecasted volumes for 2017 and 2018 (for R1 Industrial and Commercial). Please update the table with 2018 actuals and explain the lower forecast for 2017 and 2018.

Response:

(a) The adjusted R-squared of the R1 Industrial regression model is 0.863 (see Exhibit 3, Tab 2, Schedule 1, Page 11).

(b) Note that the mean absolute percentage error updated with 2018 actuals is 6.5%. A number of other variables were considered to improve the mean absolute percentage error including GDP, Ontario FTEs, London FTEs, time trends, number of days in the month, and number of work days in the month. Regressions using the natural logarithm of total consumption per customer (not excess) and using excess consumption (not natural log) as the dependent variables were run but found to be inferior.

(c) The 2018 predicted volumes per customer are lower than actual volumes per customer as a result of higher use per customer in 2018 than any previous year. The higher consumption per year is partially the result of colder than typical weather (high HDD), which is reflected in higher predicted volumes per customer. See Table 3-STAFF-39-1 for R1 Industrial and Table 3-STAFF-39-2 for R1 Commercial updated with 2018 Actuals.

Table 3-STAFF-39-1
R1 Industrial

		A	B	C
	Year	**Actual**	**Predicted**	**Absolute Error**
1	2010	24,101.1	25,300.0	5.0%
2	2011	28,608.0	24,758.4	13.5%
3	2012	24,350.5	24,736.0	1.6%
4	2013	24,752.3	26,685.2	7.8%
5	2014	26,305.8	27,890.3	6.0%
6	2015	23,185.5	25,123.6	8.4%
7	2016	22,433.0	24,052.7	7.2%
8	2017	25,831.0	24,649.7	4.6%
9	2018	28,907.8	27,540.3	4.7%
10	**Total**	**199,567.1**	**203,195.9**	**1.8%**
11	**MAPE (Annual)**			6.5%
12	**MAPE (Monthly)**			18.8%

Table 3-STAFF-39-2
R1 Commercial

		A	B	C
	Year	**Actual**	**Predicted**	**Absolute Error**
1	2010	9,215.8	9,602.9	4.2%
2	2011	9,476.8	9,848.1	3.9%
3	2012	8,515.3	8,914.4	4.7%
4	2013	10,226.6	10,025.4	2.0%
5	2014	10,963.7	10,703.6	2.4%
6	2015	9,935.2	10,102.6	1.7%
7	2016	9,065.5	9,491.1	4.7%
8	2017	10,222.5	9,442.6	7.6%
9	2018	11,257.6	9,989.5	11.3%
10	**Total**	**77,621.5**	**78,130.6**	**0.7%**
11	**MAPE (Annual)**			**4.7%**
12	**MAPE (Monthly)**			**7.4%**

3-STAFF-40
Reference: **Exhibit 3 / Tab 2 / Schedule 1/ Pgs. 15-16**

Request:

For the R3 class consumption the equation was estimated using 107 observations. The R3 Class customer count declined from 6 to 4 from October 2009 to June 2010.

EPCOR has provided the regression model for this class and a table showing the accuracy of its forecast using the model coefficients. The mean absolute percentage error is high and EPCOR has indicated that such a variance can be expected in a class with only 4 to 6 customers.

(a) Please provide the adjusted R-square of the regression model.

(b) Did EPCOR consider other forecasting methodologies in view of the small customer base in this rate class? If yes, please explain the methodologies used and provide the results.

(c) Please provide the average for the weather normalized consumption from 2013 to 2018.

Response:

(a) The adjusted R-squared of the R3 Industrial regression model is 0.890 (see Exhibit 3, Tab 2, Schedule 1, page 16).

(b) A number of other variables were considered to improve the mean absolute percentage error including GDP, Ontario FTEs, London FTEs, number of days in the month, and number of work days in the month.

The baseload and excess method, which is the method used for the other regression models, was considered but not used because the results were not as predictive. This was mainly because baseload consumption was not consistent over time. Regressions using non-natural logarithmic data were also considered but found to be inferior (mean absolute percentage error (“MAPE”) of 9.7% compared with 8.0% in the proposed model).

More straightforward regressions, such as Ordinary Least Squares ("OLS"), were run but rejected as the Durbin-Watson statistics were sufficiently different from 2. An alternate time-series model using the Cochrane-Orcutt estimation was also considered but found to have inferior results (MAPE of 8.5%).

(c) Average weather-normalized consumption for the R3 class from 2013 to 2018 was 1,670,194.6 m^3.

3-STAFF-41

Reference: **Exhibit 3 / Tab 2 / Schedule 1/ Pgs. 20-32**

Request:

EPCOR has used the normalized and forecast heating degree days to calculate the weather corrected consumption and forecast values for all the rate classes.

(a) Please update the tables with 2018 actuals for all tables that have used a 2018 forecast.

(b) The forecast consumption per customer for the R1 Industrial Class has declined significantly in 2019 and 2020 from 2017 actuals and 2018 (close to 10%). What are the reasons for the substantial decline in average consumption and does EPCOR expect such a drop to materialize?

(c) The forecast consumption per customer shows a decline in 2018 and 2019 as compared to 2017 and 2018 for R1 Commercial and R3 Customer Class. The drop for R3 customers is significant compared to all other years in the table (2010 to 2017). What are the probable reasons for the decline in average consumption?

(d) The number of customers in the R1 Industrial Class grew significantly from 2009 to 2013 so the growth rates from these years was excluded as they do not reflect the current customer growth trend. Please explain the reasons for the significant growth from 2009 to 2013 and the type of customers that were added (industrial plants, grain dryers, small manufacturing). Why is the trend not likely to continue?

Response:

(a) The following Tables have been updated with 2018 Actuals as follows:

Table 3-STAFF-41-1
Actual vs Normalized R1 Residential

		A	B	C	D	E	F
			Consumption			Normalized	
	Year	Customers	Per Customer	Total	Actual	Per Customer	Total
1	2010	6,472	1,827	11,824,006	11,839,669	1,870	12,104,165
2	2011	6,609	1,876	12,400,852	12,393,486	1,880	12,427,736
3	2012	6,896	1,705	11,756,626	11,751,822	1,885	13,001,068
4	2013	7,181	1,990	14,289,175	14,287,143	1,954	14,033,441
5	2014	7,470	2,162	16,150,603	16,127,158	2,001	14,949,404
6	2015	7,726	1,938	14,974,492	14,948,329	1,895	14,642,987
7	2016	7,956	1,813	14,425,323	14,417,053	1,878	14,938,488
8	2017	8,110	1,893	15,347,990	15,400,877	1,975	16,017,419
9	2018	8,364	2,099	17,554,151	17,571,111	2,070	17,313,830
10	2019	8,617	-	-	-	1,921	16,556,503
11	2020	8,878	-	-	-	1,920	17,045,597

Table 3-STAFF-41-2
Forecasted R1 Residential Tiered Consumption

		A	B	C
	Year	Tier 1	Tier 2	Total
1	2017	15,289,931	110,947	15,400,877
2	2018	17,201,765	112,064	17,313,830
3	2019	16,451,799	104,704	16,556,503
4	2020	16,937,809	107,788	17,045,597

Table 3-STAFF-41-3
Forecasted R1 Residential Customer Count

		A	B
	Year	Customers	Percent of Prior Year
1	2009	6,396	-
2	2010	6,472	101.2%
3	2011	6,609	102.1%
4	2012	6,896	104.3%
5	2013	7,181	104.1%
6	2014	7,470	104.0%
7	2015	7,726	103.4%
8	2016	7,956	103.0%
9	2017	8,110	101.9%
10	2018	8,364	103.1%
11	2019	8,617	103.0%
12	2020	8,878	103.0%

Table 3-STAFF-41-4
Actual vs Normalized R1 Commercial

		A	B	C	D	E	F
			Consumption			**Normalized**	
	Year	**Customers**	**Per Customer**	**Total**	**Actual**	**Per Customer**	**Total**
1	2010	405	9,216	3,736,259	3,735,278	9,455	3,833,369
2	2011	405	9,477	3,833,380	3,846,511	9,531	3,855,429
3	2012	415	8,515	3,533,844	3,526,397	9,452	3,922,470
4	2013	424	10,227	4,336,095	4,352,319	10,028	4,252,065
5	2014	437	10,964	4,795,706	4,788,282	10,096	4,416,229
6	2015	445	9,935	4,421,983	4,420,443	9,689	4,312,477
7	2016	453	9,065	4,102,131	4,117,374	9,405	4,255,919
8	2017	462	10,223	4,718,541	4,735,858	10,718	4,947,332
9	2018	477	11,258	5,367,312	5,468,007	11,118	5,300,972
10	2019	485	-	-	-	9,828	4,769,270
11	2020	494	-	-	-	9,821	4,851,704

Table 3-STAFF-41-5
Forecasted R1 Commercial Tiered Consumption

		A	B	C
	Year	**Tier 1**	**Tier 2**	**Total**
1	2017	1,980,516	2,755,342	4,735,858
2	2018	2,485,349	2,815,623	5,300,972
3	2019	2,240,849	2,528,420	4,769,270
4	2020	2,279,405	2,572,300	4,851,704

Table 3-STAFF-41-6
Forecasted R1 Commercial Customer Count

		A	B
	Year	**Customers**	**Percent of Prior Year**
1	2009	407	-
2	2010	405	99.7%
3	2011	405	99.8%
4	2012	415	102.6%
5	2013	424	102.2%
6	2014	437	103.2%
7	2015	445	101.8%
8	2016	453	101.7%
9	2017	462	102.0%
10	2018	477	103.3%
11	2019	485	101.8%
12	2020	494	101.8%

Table 3-STAFF-41-7
Actual vs Normalized R1 Industrial

		A	B	C	D	E	F
			Consumption			Normalized	
	Year	Customers	Per Customer	Total	Actual	Per Customer	Total
1	2010	43	24,101	1,034,341	960,283	25,349	1,087,887
2	2011	43	28,608	1,225,376	1,247,376	30,507	1,306,696
3	2012	51	24,350	1,252,019	1,265,913	25,084	1,289,757
4	2013	58	24,752	1,429,444	1,436,592	24,292	1,402,860
5	2014	63	26,306	1,659,456	1,666,209	24,509	1,546,119
6	2015	62	23,186	1,439,435	1,430,900	23,570	1,463,324
7	2016	65	22,433	1,461,881	1,462,707	24,695	1,609,290
8	2017	66	25,831	1,700,539	1,700,089	27,503	1,810,641
9	2018	67	28,908	1,924,775	1,945,343	27,924	1,859,241
10	2019	67	-	-	-	25,660	1,731,722
11	2020	68	-	-	-	25,636	1,743,215

Table 3-STAFF-41-8
Forecasted R1 Industrial Tiered Consumption

		A	B	C
	Year	Tier 1	Tier 2	Total
1	2017	351,414	1,348,675	1,700,089
2	2018	442,678	1,416,563	1,859,241
3	2019	390,053	1,341,669	1,731,722
4	2020	392,687	1,350,528	1,743,215

Table 3-STAFF-41-9
Forecasted R1 Industrial Customer Count

		A	B
	Year	Customers	Percent of Prior Year
1	2009	30	-
2	2010	43	141.5%
3	2011	43	99.8%
4	2012	51	120.0%
5	2013	58	112.3%
6	2014	63	109.2%
7	2015	62	98.4%
8	2016	65	105.0%
9	2017	66	101.0%
10	2018	67	101.1%
11	2019	67	101.4%
12	2020	68	101.4%

Table 3-STAFF-41-10
Actual vs Normalized R3

		A	B	C	D	E	F
			Consumption			**Normalized**	
	Year	**Customers**	**Per Customer**	**Total**	**Actual**	**Per Customer**	**Total**
1	2010	5	445,893	2,117,993	2,108,344	450,193	2,138,416
2	2011	4	616,172	2,464,687	2,464,687	617,594	2,470,374
3	2012	4	540,426	2,161,705	2,161,705	558,722	2,234,887
4	2013	4	411,186	1,644,742	1,644,742	405,282	1,621,126
5	2014	4	448,002	1,792,006	1,792,006	429,438	1,717,753
6	2015	4	423,082	1,692,328	1,692,328	424,349	1,697,395
7	2016	4	373,087	1,492,346	1,492,346	380,754	1,523,015
8	2017	5	375,566	1,690,049	1,653,466	380,454	1,712,042
9	2018	6	294,107	1,764,644	1,764,644	291,639	1,749,836
10	2019	6	-	-	-	300,218	1,801,305
11	2020	6	-	-	-	286,947	1,721,684

Table 3-STAFF-41-11
Forecasted R3 Customer Count

		A	B
	Year	**Customers**	**Percent of Prior Year**
1	2009	6	-
2	2010	5	79.2%
3	2011	4	84.2%
4	2012	4	100.0%
5	2013	4	100.0%
6	2014	4	100.0%
7	2015	4	100.0%
8	2016	4	100.0%
9	2017	5	112.5%
10	2018	6	133.3%
11	2019	6	100.0%
12	2020	6	100.0%

Table 3-STAFF-41-12
Actual vs Normalized R2 Seasonal

		A	B	C	D	E	F
			Consumption			Normalized	
	Year	Customers	Per Customer	Total	Actual	Per Customer	Total
1	2010	65	25,388	1,650,218	1,638,992	-	-
2	2011	65	27,387	1,768,757	1,849,679	-	-
3	2012	66	28,174	1,868,851	1,885,826	-	-
4	2013	64	28,302	1,820,741	1,844,495	-	-
5	2014	65	30,594	1,980,940	1,988,124	-	-
6	2015	63	20,017	1,256,038	1,242,867	-	-
7	2016	59	23,524	1,382,013	1,394,132	-	-
8	2017	55	26,211	1,435,062	1,410,653	-	1,410,653
9	2018	53	25,989	1,385,057	1,533,298	-	1,533,298
10	2019	52	-	-	-	25,608	1,322,652
11	2020	50	-	-	-	25,608	1,280,400

Table 3-STAFF-41-13
Forecasted R2 Seasonal Tiered Consumption

		A	B	C	D	E	F	G
		April 1 to Oct 31			Nov 1 to Mar 31			
	Year	Tier 1	Tier 2	Tier 3	Tier 1	Tier 2	Tier 3	Total
1	2017	101,262	857,951	129,629	71,693	244,784	5,335	1,410,653
2	2018	100,230	824,758	192,747	65,875	314,871	34,817	1,533,298
3	2019	88,064	735,588	140,527	68,342	272,142	17,988	1,322,652
4	2020	85,251	712,090	136,038	66,159	263,448	17,413	1,280,400

Table 3-STAFF-41-14
Forecasted R2 Seasonal Customer Count

		A	B
	Year	Customers	Percent of Prior Year
1	2009	71	-
2	2010	65	92.0%
3	2011	65	99.4%
4	2012	66	102.7%
5	2013	64	97.0%
6	2014	65	100.6%
7	2015	63	96.9%
8	2016	59	93.6%
9	2017	55	93.2%
10	2018	53	97.3%
11	2019	52	96.9%
12	2020	50	96.9%

Table 3-STAFF-41-15
Actual vs Forecast R4

		A	B	C	D	E	F
			Consumption			Normalized	
	Year	Customers	Per Customer	Total	Actual	Per Customer	Total
1	2010	23	11,597	269,634	267,879	-	-
2	2011	23	21,688	487,988	477,633	-	-
3	2012	25	23,036	575,898	678,458	-	-
4	2013	32	26,175	831,059	861,111	-	-
5	2014	33	39,661	1,318,721	1,345,169	-	-
6	2015	34	29,232	996,339	994,710	-	-
7	2016	35	25,140	888,266	904,160	-	-
8	2017	36	31,238	1,119,348	1,124,029	-	1,124,029
9	2018	36	29,211	1,051,596	1,145,610	-	1,145,610
10	2019	37	-	-	-	30,237	1,116,228
11	2020	38	-	-	-	30,237	1,149,006

Table 3-STAFF-41-16

Forecasted R4 Tiered Consumption

		A	B	C	D	E
		Jan 1 to Mar 31		Apr 1 to Dec 31		
	Year	Tier 1	Tier 2	Tier 1	Tier 2	Total
1	2017	13,025	1,210	84,919	1,024,874	1,124,029
2	2018	16,151	5,433	102,039	1,021,987	1,145,610
3	2019	17,490	3,541	91,612	1,003,585	1,116,228
4	2020	18,003	3,645	94,302	1,033,055	1,149,006

Table 3-STAFF-41-17
Forecasted R4 Customer Count

		A	B
	Year	Customers	Percent of Prior Year
1	2009	23	-
2	2010	23	101.1%
3	2011	23	96.8%
4	2012	25	111.1%
5	2013	32	127.0%
6	2014	33	104.7%
7	2015	34	102.5%
8	2016	35	103.7%
9	2017	36	101.4%
10	2018	36	100.5%
11	2019	37	102.5%
12	2020	38	102.5%

Table 3-STAFF-41-18
Actual vs Forecast R5

		A	B	C	D	E	F
			Consumption			Normalized	
	Year	**Customers**	**Per Customer**	**Total**	**Actual**	**Per Customer**	**Total**
1	2010	5	138,769	728,538	697,560	-	-
2	2011	5	222,975	1,114,874	1,114,874	-	-
3	2012	5	177,350	886,748	886,748	-	-
4	2013	5	203,326	1,016,630	1,016,630	-	-
5	2014	5	225,771	1,147,669	1,128,958	-	-
6	2015	5	134,524	672,622	672,622	-	-
7	2016	5	112,572	562,860	562,860	-	-
8	2017	5	186,530	870,472	753,900	-	753,900
9	2018	4	168,312	673,249	626,165	-	626,165
10	2019	4	-	-	-	171,437	685,748
11	2020	4	-	-	-	171,437	685,748

Table 3-STAFF-41-19
Forecasted R5 Customer Count

		A	B
	Year	**Customers**	**Percent of Prior Year**
1	2009	5	
2	2010	5	105.0%
3	2011	5	95.2%
4	2012	5	100.0%
5	2013	5	100.0%
6	2014	5	101.7%
7	2015	5	98.4%
8	2016	5	100.0%
9	2017	5	93.3%
10	2018	4	85.7%
11	2019	4	97.6%
12	2020	4	97.6%

Table 3-STAFF-41-20
Actual vs Forecast R6

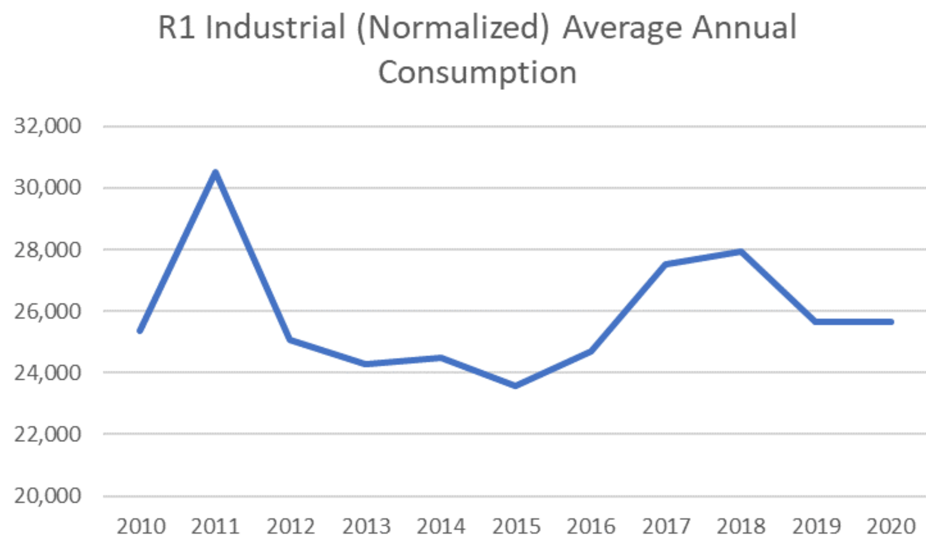
		A	B	C	D	E	F
			Consumption			**Normalized**	
			Per			**Per**	
	Year	**Customers**	**Customer**	**Total**	**Actual**	**Customer**	**Total**
1	2010	1	33,459,684	33,459,684	33,459,684	-	-
2	2011	1	30,758,504	30,758,504	30,758,504	-	-
3	2012	1	31,628,262	31,628,262	31,628,262	-	-
4	2013	1	31,582,423	31,582,423	31,582,423	-	-
5	2014	1	31,735,774	31,735,774	31,735,774	-	-
6	2015	1	34,710,609	34,710,609	34,710,609	-	-
7	2016	1	40,074,176	40,074,176	40,074,176	-	-
8	2017	1	36,485,139	36,485,139	36,485,139	-	36,485,139
9	2018	1	62,572,500	62,572,500	42,332,323	-	42,332,323
10	2019	1	-	-	-	66,699,025	66,699,025
11	2020	1	-	-	-	66,699,025	66,699,025

Table 3-STAFF-41-21
Forecasted R6 Customer Count

		A	B
	Year	**Customers**	**Percent of Prior Year**
1	2009	0	-
2	2010	0	-
3	2011	1	-
4	2012	1	100.0%
5	2013	1	100.0%
6	2014	1	100.0%
7	2015	1	100.0%
8	2016	1	100.0%
9	2017	1	100.0%
10	2018	1	100.0%
11	2019	1	100.0%
12	2020	1	100.0%

(b) The following figure is a graph of the average weather normalized annual consumption for R1 Industrial since 2011. ENGLP believes that 2018 was an unusually high consumption year and that the forecast is reasonable in the context of the historical weather normalized consumption per customer. As such, ENGLP is anticipating such a drop to materialize.

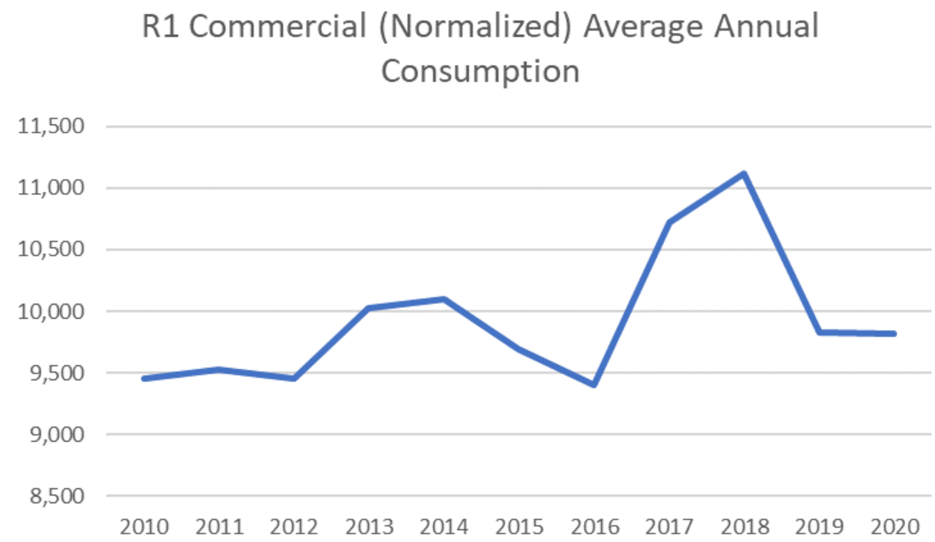
Figure 3-STAFF-41-1
Average Weather Normalized Annual Consumption for R1 Industrial
2011-2020



(c) Similar to ENGLP's response to (b) above, the forecast shows a decline in average consumption in 2018 and 2019 as compared to 2017 and 2018 for both R1 Commercial and Rate 3 customers.

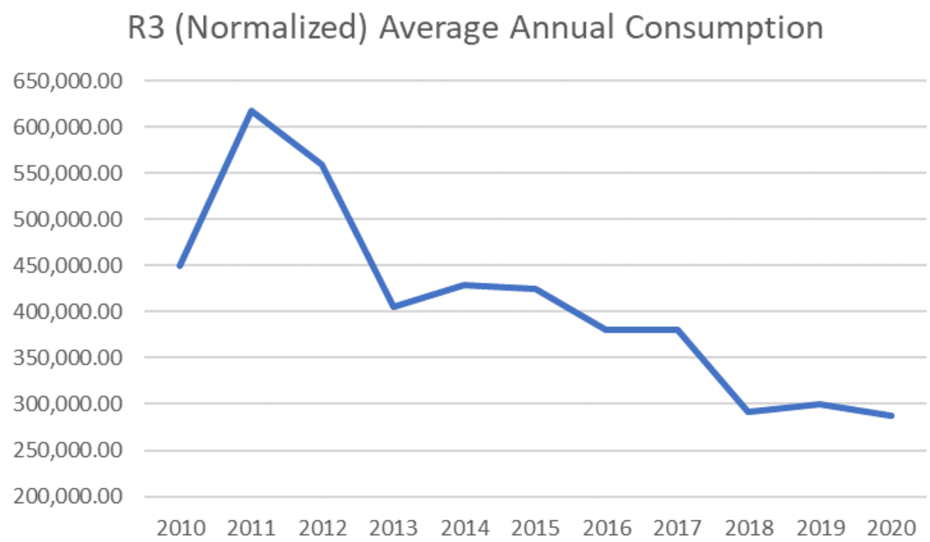
The following figure is a graph of the weather normalized annual consumption for R1 Commercial customers since 2011. The data shows that 2018 was an unusually high consumption year, and as such ENGLP believes that the forecast is reasonable in the context of the historical weather normalized consumption per customer. Therefore, ENGLP is anticipating this drop to materialize.

Figure 3-STAFF-41-2
Average Weather Normalized Annual Consumption for R1 Commercial
2011-2020



Rate 3 has seen a consistent drop in the weather normalized consumption per customer as shown in the following figure. ENGLP believes that the forecast is reasonable in the context of the historical weather normalized consumption per customer and as such is anticipating a drop to materialize.

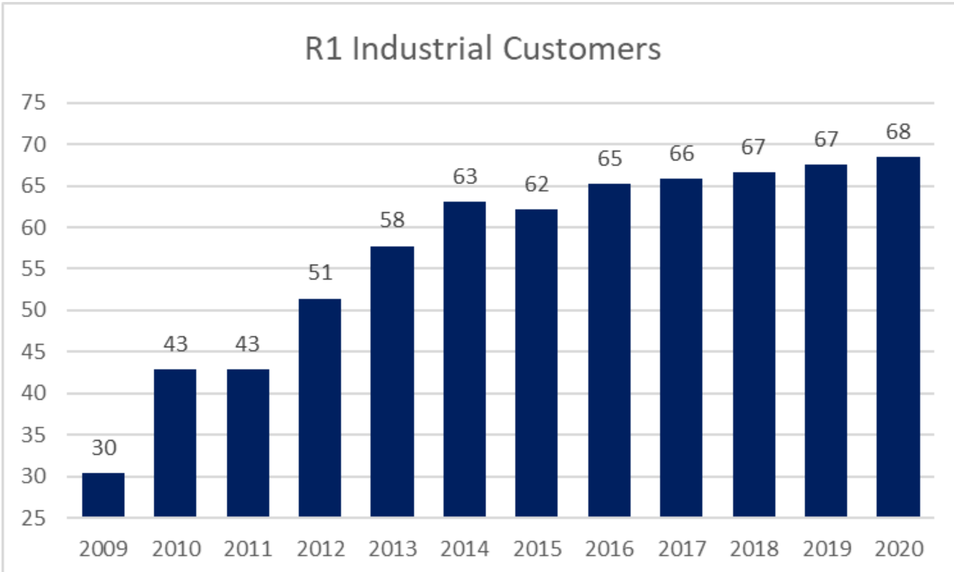
Figure 3-STAFF-41-3
Average Weather Normalized Annual Consumption for R3
2011-2020



(d) ENGLP acquired the assets of NRG on November 1, 2017 and is unable to explain the significant growth in the R1 Industrial segment from 2009–2013. EPCOR understands that in its 2016 rate filing, NRG mentions incentives and/or discounts being offered to convert customers from other fuels to gas. These incentives and/or discounts no longer exist. This could be one explanation for the increase between 2009-2013.

However, as shown in Figure 3-STAFF-41-4 below, since 2014 the growth in customer count in this segment has remained relatively flat which is why ENGLP believes the trend observed between 2009-2013 is unlikely to continue.

Figure 3-STAFF-41-4
Average Weather Normalized Annual Consumption for R3
2011-2020



4-STAFF-42

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 4-5**

Request:

Tables 4.1-6 to 4.1-8 provide forecasted commodity and transportation costs for 2018, 2019 and 2020.

(a) Please update the 2018 commodity and transportation costs with actuals.

(b) For the years 2018 and 2019 please revise the table to include the actual premium price for the one million cubic meters that has been set by the Ontario Energy Board in EB-2010-0018.

(c) The OEB allowed NRG to purchase up to one million cubic meters annually from an affiliate at a price of $8.486 per mcf. in order to address system integrity issues (Phase 2 Decision, EB-2010-0018, May 17, 2012). This was a temporary measure until NRG found a permanent solution. Please provide the excess premium paid (annual cost) by customers for the one million cubic meters as compared to the average cost of gas (excluding the premium purchase) for each of the years from 2013 to 2018.

Response:

(a) See ENGLP's response to 1-STAFF-03.

(b) See ENGLP's response to 1-STAFF-03.

(c) See Table 4-STAFF-42-1 below for the commodity cost difference resulting from volumes purchased at Tranche A contract price ($8.486 per mcf).

Table 4-STAFF-42-1
Cost Difference Resulting from Volumes Purchased at Tranche A Contract Price
($)

		A **2013**	B **2014**	C **2015**	D **2016**	E **2017**	F **2018**
1	Cost Differential	122,541	99,778	89,039	173,736	139,783	138,415

4-STAFF-43

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 4-5**

Request:

EPCOR executed a Gas Purchase Agreement that included the right of NRG Corp. to sell up to one million cubic meters of gas to EPCOR at a rate of $8.486 per mcf. The Gas Purchase Agreement expires on September 20, 2020.

Please provide the Gas Purchase Agreement that was executed between EPCOR and NRG Corp. (now On-Energy Corp.).

Response:

See 4-STAFF-43 Attachment 1 for the Gas Purchase Agreement executed between EPCOR and NRG Corp.

EPCOR NATURAL GAS LIMITED PARTNERSHIP
Buyer

- and -

NRG CORP.
Seller

November 1, **2017**

GAS PURCHASE AGREEMENT

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GAS PURCHASE AGREEMENT

THIS AGREEMENT is made as of the 1 day of November, 2017.

BETWEEN:

EPCOR Natural Gas Limited Partnership, a limited partnership existing under the laws of the Province of Ontario (hereinafter referred to as **"Buyer"**)

-and-

NRG Corp., a body corporate, with offices in the City of London, in the Province of Ontario (hereinafter referred to as **"Seller"**)

RECITALS:

1. Buyer has entered into an Asset Purchase Agreement to acquire the natural gas distribution assets of Natural Resource Gas Limited (**"NRGL"**), a related company of Seller (the **"Acquisition"**).

2. NRGL currently receives the majority of its gas supply from Union, delivered to certain entry points situated in the northerly and easterly parts of NRGL's distribution system. NRGL also currently purchases certain Supplies from Seller, which produces these Supplies from approximately forty local gas wells listed in Schedule "A" hereto (the "**Wells**") situated within the franchise areas served by NRGL as such purchases are to meet a system integrity need in the southern part of the distribution system.

3. The existing gas supply arrangements between NRGL and Seller are not being assigned to the Buyer and, as a condition to completion of the Acquisition, Buyer and Seller are to enter into a gas purchase agreement for the purchase of Supplies.

4. The Parties hereto wish to enter into this gas purchase agreement (the "**Agreement**") whereby Supplies are sold by Seller to Buyer and delivered at various Delivery Locations situated in the southeasterly part of the Distribution System.

NOW THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1 - INTERPRETATION

1.1 In addition to capitalized terms defined elsewhere in this Agreement, the following terms shall have the following meanings:

(a) **"Business Day"** shall mean any day, other than Saturday, Sunday, and other days which are statutory holidays in the Province of Ontario;

(b) **"cubic foot of gas"** shall mean the volume of gas contained in one (1) cubic foot of space at a pressure of fourteen and seventy-three hundredths (14.73) psia, at a temperature of sixty degrees Fahrenheit (60°F);

(c) **"Delivery Location"** shall mean the properties which contain a meter station which receive from the Wells and measure the volumes of Supplies entering the Distribution System;

(d) **"Dawn Reference Price"** shall mean the landed cost of natural gas for Union's sales service as determined by Union from time to time;

(e) **"Delivery Point"** shall mean at each Delivery Location, the outlet of the flange connecting the Distribution System to Seller's pipe that transports gas from the relevant Well;

(f) **"Distribution System"** shall mean the natural gas distribution system currently owned and operated by NRGL, to be acquired by Buyer on the Effective Date;

(g) **"Effective Date"** shall mean the closing date of the Acquisition;

(h) **"Force Majeure Event"** shall have the meaning ascribed to it in Section 18.1;

(i) **"Gas Year"** with respect to the first "Gas Year", shall mean the period commencing on the Effective Date and ending on the following September 30, and with respect to any succeeding "Gas Year" shall mean the period of twelve (12) consecutive months from the end of the preceding Gas Year to the next succeeding September 30;

(j) **"Gas"** shall mean natural gas;

(k) **"Good Industry Practice"** means any of the practices, methods and acts that, in the exercise of reasonable commercial judgment in the light of the facts known, or that reasonably should be known, to the Party, applicable at the time that a decision was made, could reasonably have been expected to accomplish the desired result in a cost-effective manner consistent with contractual obligations, Applicable Laws, licensing and regulatory considerations, environmental considerations, reliability, safety and expedition and other relevant considerations reasonable in the circumstances. Good Industry Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts employed by owners and prudent and experienced operators of facilities similar in size, design, capacity and operational characteristics, including those involving the use of new concepts or technology, and having due regard for practices followed from time to time by the natural gas industry;

(l) "**Initial Gas Year**" shall mean the first Gas Year during the Term;

(m) "**Mcf**" shall mean one thousand (1,000) cubic feet of natural gas;

(n) "**Minimum Supply Volume**" shall mean in respect of any Gas Year, 17,747 Mcf;

(o) "**OEB**" means Ontario Energy Board;

(p) "**Party**" means either party to this agreement and "**Parties**" means both of them;

(q) "**Supplies**" shall mean Gas produced from the Wells to be delivered into the Distribution System;

(r) "**Tranche A Price**" has the meaning given to such term in Section 5.1, as approved by the OEB from time to time;

(s) "**Tranche A Volume**" has the meaning given to such term in Section 5.1;

(t) "**Tranche B Price**" has the meaning given to such term in Section 5.1, as approved by the OEB from time to time;

(u) "**Tranche B Volume**" has the meaning given to such term in Section 5.1;

(v) "**Union**" means Union Gas Limited; and

(w) "**Union's General Terms and Conditions**" means Union's general terms and conditions for its M12 contracts, as may be amended from time to time, a current copy of which is attached in Schedule "B" hereto.

1.2 The numbering and descriptive headings of particular provisions of this Agreement are for the purpose of facilitating administration and shall not be construed as having any substantive effect on the terms of this Agreement.

1.3 Schedules "A" and "B" attached hereto are hereby incorporated into and made a part of this Agreement.

ARTICLE 2 - CONDITION PRECEDENT

2.1 This Agreement does not become effective unless and until the Acquisition is completed. If the Buyer and NRGL do not complete the Acquisition and terminate the purchase agreement related thereto, this Agreement will terminate and neither party will have any obligation or liability related hereto.

ARTICLE 3 - TERM

3.1 Subject to Section 2.1, this Agreement shall become effective on the Effective Date and shall, except as herein otherwise specifically provided, continue in full force and effect until September 30, 2020 (the **"Term"**). Buyer shall have the option, but not the obligation, to request extensions of the Term, on one or more occasions, for additional Gas Years or portions thereof by providing written notice to Seller at least ninety (90) days prior to the end of the Term or any subsequent Gas Year. Seller shall consider any such extension request, and shall agree to, or deny, such request within thirty (30) days of the receipt of such request from Buyer.

3.2 Following expiry of the Term, including any extensions, the Parties agree to enter into a further agreement, pursuant to which Buyer will continue to buy Gas from Seller, provided that entering into such further agreement would not: (i) constitute an imprudent utility action by Buyer; and (ii) materially and adversely affect Buyer's ability to apply for or carry out a material capital project or other enhancement or extension of the Distribution System. The Parties further agree that the purchase price for any Supplies under such further agreement shall be at the then current Tranche B Price, as is adjusted from time to time.

ARTICLE 4 - SUPPLY AND PURCHASE COMMITMENTS

4.1 (a) Seller acknowledges that the Supplies are intended to help provide system integrity for the Distribution System.

(b) Subject to any Force Majeure Event, Seller will:

(i) use its best efforts to produce Gas from the Wells for sale to the Buyer;

(ii) supply the Minimum Supply Volume to Buyer; and

(iii) during peak flow months (which are the months of November to March inclusive), continue to deliver available Supplies to Buyer.

(c) Seller commits and dedicates exclusively to the performance of this Agreement all Gas produced from the Wells and, as contemplated by the ARTICLE 7 hereof, any future wells developed by the Seller in the region of the Wells.

(d) Buyer will purchase all Supplies tendered by Seller which are received and metered by Buyer at each Delivery Point, for subsequent delivery into the Distribution System, provided that all such purchases shall be subject to:

(i) the quality of Supplies meeting the terms and conditions of this Agreement;

(ii) Force Majeure Events that impair the Seller's ability to supply or deliver Gas into the Distribution System, or Buyer's ability to transport such Supplies from the Delivery Point to customers; and

(iii) Buyer's right to shut-in production from the Wells, as set out in Section 9.3.

ARTICLE 5- PRICE

5.1 The Parties acknowledge that:

(a) the OEB currently authorizes NRGL to recover from its customers, the costs associated with NRGL's purchase of a portion of the Supplies in each Gas Year (the "**Tranche A Volume**") at a price (the "**Tranche A Price**") above the market price for Gas as such Supplies provide system integrity to the Distribution System;

(b) the current Tranche A Price is $8.486/Mcf and the current Tranche A Volume is 35,494 Mcf per Gas Year;

(c) the volume of Supplies purchased by NRGL in any Gas Year in excess of Tranche A Volume (the "**Tranche B Volume**") and the price paid for such volumes (the "**Tranche B Price**") requires OEB approval for recovery of the associated cost of purchasing such volume, and that, currently, the Tranche B Price changes quarterly and is equal to the Dawn Reference Price; and

(d) NRGL has, in its current, but suspended, rate application filed with the OEB as EB-2016-0236, requested that the Tranche A Volume be increased from 35,494 Mcf to 53,240 Mcf.

5.2 The price to be paid by Buyer to Seller, for volumes offtaken by EPCOR up to the Tranche A Volume will be the Tranche A Price and, for any volume thereafter will be the Tranche B Price.

5.3 Buyer agrees that if a determination on the increased Tranche A Volume in EB-2016-0236 is not made prior to the closing of the Acquisition, it will include the request for a Tranche A Volume increase to 53,240 Mcf in its initial rate application, provided that:

(a) such request would not be an imprudent utility action; and,

(b) NRGL or Seller will provide EPCOR with relevant evidence to support such request.

5.4 The Parties agree that for the Initial Gas Year, the volume purchased at the Tranche A Price will be equal to the approved Tranche A Volume less the volume purchased by NRGL from Seller for the period from October 1, 2016 to the Effective Date which attracted a premium price.

ARTICLE 6 - FORECASTS

6.1 No later later than 90 days prior to any Gas Year excluding the Initial Gas Year, Seller shall provide to Buyer a forecast of the volume of Supplies that Seller will use best efforts to produce and deliver to the Delivery Points in each of the following three (3) Gas Years. Each such forecast shall include, for the Wells and Delivery Points in the aggregate:

(a) estimated minimum daily volumes to be delivered for the following two (2) winter periods;

(b) estimated monthly volumes to be delivered for the following Gas Year;

(c) estimated annual volumes to be delivered for all three Gas Years; and,

(d) any plans by Seller to discontinue or take steps to reduce total production from the Wells.

ARTICLE 7 - RIGHT OF FIRST REFUSAL RE PRODUCTION FROM NEW WELLS

7.1 If during the Term of this Agreement, Seller develops or otherwise acquires production rights to any new gas wells ("**ROFR Wells**") in the region where the Wells are located, Seller will forthwith give Buyer notice of same and Buyer shall have a right of first refusal ("**ROFR**"), but no obligation, to purchase any commercial production from such ROFR Wells, on the following terms:

(a) in any Gas Year, in the event that the aggregate amount of Supplies delivered by Seller from the Wells is less than 35,494 Mcf, for the difference between Supplies delivered and 35,494 Mcf, the price payable for Gas delivered to the Delivery Points from the ROFR Wells shall be the applicable OEB approved price; and

(b) for any other volume of Gas, at a price of $8.486 per Mcf.

7.2 Buyer shall have 30 days from the date of notification provided by Seller in Section 7.1 above to exercise its ROFR.

ARTICLE 8 – DELIVERY, PRESSURE AND PRESSURE PROTECTION

8.1 Seller shall supply the Supplies to each Delivery Point at each Delivery Location. Supplies will not be considered delivered to Buyer unless and until such Gas has been metered.

8.2 Supplies supplied by Seller at each Delivery Point shall not exceed 80 pounds per square inch gauge.

8.3 For the purposes of Section 8.2, Buyer shall specify to Seller the maximum allowable delivery pressure ("**MAOP**") for each Delivery Point.

8.4 Seller will employ the necessary over pressure protection and volume control systems so as to not exceed the MAOP of the Distribution System downstream of each Delivery Point and protect against over-pressuring of Buyers facilities.

ARTICLE 9- QUALITY OF- SERVICE

9.1 Seller agrees to carry out planned maintenance on the Wells in accordance with the following terms:

(a) planned maintenance will be limited to ten (10) days in any Gas Year;

(b) if any planned maintenance of the Wells could detrimentally impact the volume of Supplies produced from the Wells, Seller agrees to defer such planned maintenance to off-peak gas flow months; and,

(c) Seller will provide Buyer with commercially reasonable prior notice, which at a minimum shall be five (5) days, before curtailing any Supplies for planned maintenance, which notice shall include details regarding duration and extent of such curtailment.

9.2 In the event that Seller needs to curtail Supplies due to a Force Majeure Event or to carry out unplanned maintenance ("**Unscheduled Curtailment**") during any peak flow month:

(a) the Seller will provide as much notice to Buyer as is possible in the circumstances; and

(b) the Parties will work cooperatively to accommodate the Unscheduled Curtailment taking into account (1) the nature of the maintenance work to be done, and (2) the forecasted demand of the Distribution System during the Unscheduled Curtailment.

9.3 Buyer shall have the right, at no cost or penalty to Buyer, to require Seller to shut-in production from any of its Wells for a period of time to be determined by Buyer (a "**Shut-in Event**") only:

(a) to conduct maintenance on the Distribution System; and,

(b) for demonstrable Distribution System integrity purposes to ensure that the Distribution System is able to balance overall demand for Gas and Buyer's aggregate Gas supplies.

9.4 Seller may, in accordance with reasonable and prudent gas field practice, shut in production from the Wells, provided that (a) the Minimum Supply Volume is met, and (b) shut in may only occur during non-peak flow months unless otherwise agreed to by Buyer.

ARTICLE 10 - GAS QUALITY

10.1 The Gas to be delivered hereunder shall conform to Union's gas quality specifications: (a) as set out in Union's M12 Contract's General Terms and Conditions, and under applicable law (collectively, "**Gas Quality**").

10.2 In the event that any Supplies fail to meet the Gas Quality specifications set out in Section 10.1, without prejudice to any other rights and remedies otherwise available to the Purchaser at law or in equity:

(a) Buyer shall have the right to reject delivery of any Supplies at the applicable Delivery Point; and,

(b) Seller shall be deemed to have failed to supply such quantities of Gas that fail to meet the Gas Quality.

ARTICLE 11- BILLING AND PAYMENTS

11.1 Commencing with the month immediately following Effective Date Seller shall, on or before the seventh (7^{th}) Business Day of that and each subsequent month, render to Buyer an invoice for Supplies delivered to Buyer at all Delivery Points in the preceding month (an "**Invoice**"), showing the total corrected volume of Supplies supplied at each Delivery Point and the price(s) applicable to such Gas, including whether delivered from the Wells or the ROFR Wells, as applicable.

11.2 Buyer shall pay, via cheque or direct deposit, all amounts due to Seller no later than thirty (30) days after receipt of an Invoice. If Buyer does not pay amounts properly due to Seller, interest on such unpaid amount shall accrue at a rate per annum equal to the Prime Rate plus two percent (2%) from the time payment would have been due until the payment is made.

ARTICLE 12- TITLE AND RISK

12.1 Title to all Supplies hereunder shall pass from Seller to Buyer when it is delivered into the Distribution System at the Delivery Point. All costs and expenses of delivering the Supplies to a Delivery Point shall be borne by Seller except to the extent herein otherwise specifically provided. All costs and expenses of transporting the Supplies beyond the Delivery Point shall be borne by Buyer.

12.2 Seller shall be, or shall be deemed to be, in exclusive control and possession of the Supplies to be sold hereunder and responsible for any loss, damage or injury caused thereby until such Supplies are delivered into the Distribution System at the Delivery Point, at which time Buyer shall be deemed to be in exclusive control and possession of such Supplies and responsible for any loss, damage or injury caused thereby.

ARTICLE 13 – MEASUREMENT AND EQUIPMENT

13.1 Unless herein otherwise specifically provided, Buyer is responsible for measurement of the Supplies delivered into the Distribution System, and the unit of measurement of the Supplies shall be in Mcf. By the 5^{th} Business Day of the month during the Term, Buyer shall read the meters at each Delivery Point, compile the delivery data, and provide Buyer with metering information for the immediately preceding month.

13.2 For the purposes of determining volume of Supplies purchased hereunder, the volume measured by Buyer shall be adjusted according to methods contained in the regulations to the *Electricity and Gas Inspection Act*.

13.3 Buyer shall maintain all meters used for the purposes of billing Buyer under this Agreement in good working order and in compliance with all applicable laws, including the *Electricity and Gas Inspection Act* and any applicable regulations thereunder

13.4 All equipment installed by Buyer or any predecessor in title at each Delivery Location shall remain the property of Buyer. Buyer shall be entitled to remove said equipment at any time within sixty (60) days from any termination or expiry of this Agreement or the permanent discontinuance of Supplies by Seller at any Delivery Point. Seller shall take all necessary steps to ensure that Buyer may enter onto Delivery Locations to remove such equipment for a period of sixty (60) days after termination or expiry of this Agreement.

13.5 Seller shall:

(a) possess or obtain a registered lease, freehold interest or other appropriate real property right in respect of each Delivery Location sufficient to provide Buyer with free, uninterrupted access, to, from, under and above the Delivery Location, for a term (and extended terms) at least as long as this Agreement, plus sixty (60) days, and shall provide Buyer with a bona fide copy of such agreement or instrument upon request by Buyer; and

(b) maintain each Delivery Location in the state it exists as of the date of this Agreement and in a safe and workmanlike manner in accordance with all applicable laws and good industry practice.

ARTICLE 14- WARRANTY OF TITLE

14.1 Seller hereby warrants that at the time of each delivery of Supplies: (a) Seller possesses a licence to operate the Wells and produce Gas in the Province of Ontario, (b) Seller has good title and the right to sell to Buyer the Supplies delivered hereunder, and (c) all such Supplies shall be free from any and all liens, encumbrances and adverse claims of any nature, including without limitation any taxes, royalties or joint venture payments owing to others which for greater certainty are the sole responsibility of and will be paid by Seller.

ARTICLE 15 - ASSIGNMENT

15.1 The terms, covenants and conditions hereof shall be binding on the Parties hereto and on their successors and permitted assigns.

15.2 Neither Party may assign its interest under this Agreement without the prior written consent of the other, such consent not to be unreasonably withheld, except:

(a) in the case of Seller, if Seller sells, assigns or otherwise disposes of all of the Wells in accordance with Section 15.3; or

(b) in the case of Buyer, to a purchaser of all or substantially all of the Distribution System who assumes all of the Buyer's obligations hereunder.

15.3 Seller may sell, assign or otherwise dispose any or all Wells and all rights associated therewith, and may permit any change of control, direct or indirect, of Seller at any time, provided that:

(a) Seller demonstrates to satisfaction of Buyer, acting reasonably, that the assignee or new owner of Seller has the competency to operate the Wells and perform Seller's obligations under this Agreement; and,

(b) additionally, in the case of a sale, assignment or disposal of the Wells, that such assignee assumes all of Seller's obligations under this Agreement.

ARTICLE 16 - OPTION TO PURCHASE WELLS

16.1 At any time during the Term, Buyer shall have the right ("**Option**") to purchase the rights related to the Wells and all related assets (collectively, the "**Well Assets**") from Seller by providing written notice to Seller.

16.2 If Buyer wishes to exercise its Option, Buyer shall provide written notice of same to Seller, and, subject to section 16.3 of this Agreement, the Parties agree that, subject to any applicable regulatory or similar approvals or third party consents, the closing date of the acquisition of the Well Assets shall be ninety (90) days from the provision of such notice ("**Asset Closing Date**").

16.3 In the event that Buyer exercises its Option, the Parties agree that the purchase price for the Well Assets shall be the greater of: (i) the current net book value of the Well Assets, exclusive of any retirement or remediation liabilities in respect of the Well Assets, less $260,000; and (ii) the price offered to Seller from a bona fide, arm's length purchaser of the Well Assets pursuant to a binding offer to purchase which requires the sale of the Well Assets to be completed within ninety (90) days of such offer or letter of intent, less $260,000.

16.4 For greater certainty, if:

(a) Buyer provides notice to Seller that it proposes to exercise its Option and Seller has already received, or prior to the Asset Closing Date receives, a binding bona fide offer for the Well Assets, Seller will advise Buyer of same and Buyer may elect in its sole discretion to revoke the exercise of its Option and will have no further obligation or liability with respect to the purchase of the Well Assets, and Seller will be entitled to sell the Well Assets, subject to compliance with the other terms of this Agreement; and

(b) at any time during the Term, Seller receives from a bona fide, arm's length party, a binding offer to purchase the Well Assets, before accepting same, Seller shall forthwith give written notice of same to Buyer who shall have a period of thirty (30) days to exercise its Option.

ARTICLE 17 - TERMINATION

17.1 If either Party: (a) becomes insolvent within the meaning of the *Bankruptcy and Insolvency Act* (Canada), (b) makes an assignment for the general benefit of creditors or an assignment in bankruptcy, (c) receives a petition or an order in bankruptcy, (d) files a plan or proposal under any bankruptcy, (e) has any proceeding commenced by or against it for relief under any bankruptcy or insolvency laws or any laws relating to winding up or liquidation, or (f) breaches a material provision of this Agreement and fails to remedy such breach within sixty (60) days of notice of such from the other Party, the other Party may immediately, on notice to the first Party, terminate this Agreement. Termination pursuant to this Section 17.1 shall not affect any liabilities accrued to the date of termination or thereafter and shall be in addition to and not derogate from any other right or remedy available at law.

ARTICLE 18 - FORCE MAJEURE

18.1 Neither party shall be liable for any failure of delay in the performance of its obligations or be in breach of this Agreement if an to the extent such failure or delay is caused by events, occurrences or circumstances beyond the control of the party claiming same (a **"Force Majeure Event"**) which by the exercise of reasonable efforts, such Party is unable to prevent or overcome, including without limitation, acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, terrorism, sabotage, wars (declared or undeclared), blockades, insurrections, riots, diseases or epidemics, landslides, lightning, fire, earthquakes, storms, subsidence, floods, high waters, washouts, orders or acts of civil or military authorities, changes in law, civil disturbances, or any other causes, whether of the kind herein enumerated or otherwise; provided that Force Majeure Events shall not include reservoir failure or depletion and the settlement of strikes, lockouts and other industrial disturbances shall be entirely within the discretion of the particular Party involved therein and such Party may make settlement thereof in such time and on such terms and conditions as it may deem to be advisable and no delay in making such settlement shall deprive such Party of the benefits of this Agreement with respect to an Force Majeure Event.

18.2 Neither Party shall be entitled to the benefit of the provisions of Section 18.1 under any or all of the following circumstances, unless otherwise specifically provided for in Section 18.1:

(a) to the extent that the failure or delay was caused by the contributory negligence of the Party claiming a Force Majeure Event;

(b) to the extent that the failure or delay was caused by the Party claiming a Force Majeure Event having failed to exercise reasonable efforts to remedy the event, occurrence or circumstance, and to resume the performance of such covenants or obligations, with reasonable dispatch; or

(c) if the failure or delay was caused by lack of funds or with respect to the payment of any amount or amounts then due hereunder;

(d) unless as soon as reasonably possible after the happening of the Force Majeure Event relied upon or as soon as possible after determining that the Force Majeure Event would affect the claiming Party's ability to observe or perform any of its covenants or obligations under this Agreement, the Party claiming the Force Majeure Event shall have given to the other Party notice, to the effect that the claiming Party is unable by reason of a Force Majeure Event (the nature whereof shall be therein specified) to perform the particular covenants or obligations. The Party claiming a Force Majeure Event shall likewise give notice, as soon as possible after the Force Majeure Event no longer affects that Party`s performance or observance and that such Party has resumed, or is then in a position to resume, the performance or observance of such covenants or obligations.

18.3 A Force Majeure Event shall only extend the Term of this Agreement by agreement of the parties.

ARTICLE 19 - NOTICES

19.1 Except as otherwise herein specifically provided, any notice shall be given in writing. Written notice shall be deemed given on the earlier of (i) the date received by the addressee when delivered by hand, (ii) the Business Day following the date sent by facsimile (receipt confirmed) to the numbers set forth below, (iii) five (5) days after mailing by prepaid registered mail, directed to the post office address of the parties as follows (provided that, at any time when there is a strike or pending strike affecting delivery of mail, all such deliveries shall be made by hand or by facsimile), or (iv) or any other means provided that no such notice shall be deemed to have been properly received unless and until it is actually delivered to and received by the individual for whom it is intended:

To Seller: NRG Corp.

____
Attention: ____________________
Facsimile: __________

To Buyer: EPCOR Natural Gas Limited Partnership

2000 – 10423 – 101 Street NW
Edmonton, Alberta T5H 0E8
Attention: Bruce Brandell
Facsimile: (780) 412-3013

with a copy to:

EPCOR Utilities Inc.
2000 – 10423 – 101 Street NW
Edmonton, Alberta T5H 0E8
Attention: Associate General Counsel
Facsimile: 780-441-7118

or at such other address as either party may from time to time specify as its address for such purposes by written notice given pursuant to this Section.

ARTICLE 20 - MISCELLANEOUS

20.1 No waiver by either Seller or Buyer of any default by the other under this Agreement shall (a) be binding unless it is in writing and signed by the Party to be bound, or (b) operate as a waiver of any future default, whether of like or different character or nature. The failure or delay of a party in exercising any right under this Agreement will not operate as a waiver of that right.

20.2 The Parties agree and acknowledge that the purchase of Supplies by Buyer from Seller remains subject to any applicable OEB approvals, including with respect to volume, price and full cost recovery of the Supplies and the effective date for any changes to volumes and price will be if and as approved by the OEB. Without derogation to the foregoing sentence, if at any time, the OEB does not authorize Buyer to recover the full cost of the Supplies from its customers, Seller will indemnify Buyer for any differences between the amounts previously paid to Seller and the amounts approved for recovery and, in connection therewith, Buyer shall be entitled to set off such differences against any amounts payable to Seller.

20.3 This Agreement shall be governed by and construed according to the laws of Ontario, Canada.

20.4 Except as otherwise ordered by any government agency or regulatory body or as otherwise required by applicable law, the terms and conditions of this Agreement shall not be disclosed to third parties without the other Party's consent.

20.5 If any provision of this Agreement is determined to be illegal, invalid or unenforceable by any court having jurisdiction, it will be ineffective only to the extent of its illegality, invalidity or unenforceability without affecting the validity or the enforceability of the remaining provisions of this Agreement and without affecting its application to other parties or circumstances.

20.6 This Agreement may be amended only by a written instrument executed by the Parties hereto. This Agreement contains the entire understanding of the Parties with respect to the matters contains herein and supersedes all other understandings, agreements, representations, negotiations, communications and discussions, written or oral, made by the Parties or their affiliates with respect thereto. There are no representations, warranties, terms, conditions, promises, covenants or other understandings, express or implied, other than those expressly set forth herein.

20.7 Unless otherwise expressly specified herein, each Party shall be responsible for all costs and expenses (including the fees and disbursements of legal counsel, bankers, investment bankers, accountants, brokers and other advisors) incurred by it in connection with this Agreement and the transactions contemplated by it.

20.8 Time shall be of the essence.

20.9 This Agreement may be executed in any number of counterparts (including counterparts by facsimile or electronic scan), each of which will be deemed to be an original and all of which, taken together, will be deemed to constitute one and the same instrument. Delivery by facsimile or by electronic transmission of an executed counterpart of this Agreement is as effective as delivery of an originally executed counterpart of this Agreement.

[*Remainder of page intentionally left blank. Signature page to follow.*]

IN WITNESS WHEREOF this Agreement is executed in multiple originals effective as of the day and year first before written.

EPCOR Natural Gas Limited Partnership,
by its general partner, **EPCOR Ontario Utilities Inc.**

Per: ______________________

Name and Title: Stephen Stanley
SENIOR VICE PRESIDENT
COMMERCIAL SERVICES

Per: ______________________

Name and Title: Shauna Sicotte
Senior manager, Commercial Financial management.

NRG Corp.

Per: ______________________

Name and Title: ______________________

Per: ______________________

Name and Title: ______________________

IN WITNESS WHEREOF this Agreement is executed in multiple originals effective as of the day and year first before written.

EPCOR Natural Gas Limited Partnership, by its general partner, **EPCOR Ontario Utilities Inc.**

Per: ______________________

Name and Title: ______________________

Per: ______________________

Name and Title: ______________________

NRG Corp.

Per: ______________________

Name and Title: ANTHONY GRAAT
SECRETARY + TREASURER

Per: ______________________

Name and Title: ______________________

SCHEDEULE "A" attached to and forming part of a Gas Purchase Agreement dated ____________________, ______ between EPCOR Natural Gas Limited Partnership, as Buyer, and NRG Corp., as Seller.

Well	Address
NRG 80-20	850 Cty Rd 28, Langton , ON NOE 1G0
NRG 80-21	Beach Lane and 1st Con ENR, Langton, ON NOE 1G0
NRG 80-25	1554 2nd Con Rd, ENR, Langton, ON NOE 1G0
NRG 80-28	3rd Con & Reg Rd 23 & 8th, Langton, ON NOE 1G0
NRG 80-29	735 Cty Rd 28, Langton, ON NOE I GO
NRG 90-01	2nd Con ENR & Barth Side Rd, Langton, ON NOE 1G0
NRG 90-02	2nd Con ENR & Barth Side Rd, Langton, ON NOE 1G0
NRG 90-03	1527 Cty Rd 28, Langton, ON NOE 1G0
NRG 90-04	1499 2nd Con Rd, ENR, Langton, ON NOE 1G0
NRG 91-01	East of #96 Fairground Rd, Langton, On NOE 1G0
NRG 92-01	Fairground & 5th Con, ENR, Langton, ON NOE 1G0
NRG 01-01	1st Con, ENR & Fairground Rd, Langton On NOE 1G0
NRG 01-02	1st Con, ENR & Beach Lane, Langton On NOE 1G0
NRG 02-02	1st Con, ENR & Fairground Rd, Langton On NOE 1G0
NRG 03-01	820 2nd Con Rd, ENR, Langton, ON NOE 1G0
NRG 04-03	325 Fairground Rd (back), Langton, ON NOE 1G0
NRG 05-01	325 Fairground Rd , Langton, ON NOE 1G0
NRG 05-03	Woodworth & Nova Scotia Line,(Bayham) Port Burwell, ON NOJ 1TO
NRG 05-04	53816 Nova Scotia Line,(Bayham) Port Burwell, ON NOJ 1TO
NRG 05-05	356 Fairground Road, Langton, ON NOE 1G0
NRG 05-08	53816 Nova Scotia Line,(Bayham) Port Burwell, ON NOJ 1TO
NRG 05-09	2nd Con ENR & Fairground Rd, Langton, ON NOE 1G0
NRG 06-01	Vienna Line & Woodworth Rd (Bayham), Port Burwell, ON NOJ 1TO
NRG 06-04	53955 Nova Scotia Line, Port Burwell ON NOJ 1TO
NRG 06-06	2nd Con ENR & Beach Lane, Langton, ON NOE 1G0
NRG 06-08	Nova Scotia Line and Richmond Line, Port Burwell, ON NOJ 1TO
NRG 06-09	Nova Scotia Line (across from 53816), Port Burwell, ON NOJ 1TO
NRG 06-10	Nova Scotia Line (across from 53816), Port Burwell, ON NOJ 1TO
NRG 07-01	4784 Richmond Line, Port Burwell, ON NOJ 1TO
NRG 07-06	53927 Nova Scotia Line, Port Burwell, ON NOJ 1TO
NRG 07-09	Nova Scotia Line & Richmond Line, Port Burwell, ON NOJ 1TO
NRG 08-02	1499 2nd Con Rd, ENR, Langton, ON NOE 1G0
NRG 08-03	1st Con ENR and Fairground Road, Langton, ON NOE 1J0
NRG 09-01	1554 2nd Con Rd, ENR, Langton, ON NOE I GO
NRG 13-01	53564 James Line Aylmer, ON N5H 2R5
*NRG 02-03	Barth Side Road and 2nd ENR, Langton, ON NOE 1G0
*NRG 03-02	Fairground & 1st Con, ENR, Langton, ON NOE 1G0
*Hemlock 15	Lower Side Rd and Nort Rd,, Langton, ON NOE 1GO
*Hemlock 18/19	Lower Side Rd and Nort Rd, Langton, ON NOE 1G1
*Hemlock 21	Lower Side Rd and Nort Rd,, Langton, ON NOE 1G2

*50% ownership in well.

SCHEDEULE "B" attached to and forming part of a Gas Purchase Agreement dated ____________________, ______ between EPCOR Natural Gas Limited Partnership, as Buyer, and NRG Corp., as Seller.

See attached.

RATE M12
GENERAL TERMS & CONDITIONS

I. DEFINITIONS

Except where the context expressly requires or states another meaning, the following terms, when used in these General Terms & Conditions and in any contract into which these General Terms & Conditions are incorporated, shall be construed to have the following meanings:

"**Authorized Overrun**" shall mean the amount by which Shipper's Authorized Quantity exceeds the Contract Demand;

"**Available Capacity**" shall mean at any time, Union's remaining available capacity to provide Transportation Services;

"**Business Day**" shall mean any day, other than Saturday, Sunday or any days on which national banks in the Province of Ontario are authorized to close;

"**Contract**" shall refer to the Contract to which these General Terms & Conditions shall apply, and into which they are incorporated;

"**Contract Year**" shall mean a period of three hundred and sixty-five (365) consecutive days; provided however, that any such period which contains a date of February 29 shall consist of three hundred and sixty-six (366) consecutive days, commencing on November 1 of each year; except for the first Contract Year which shall commence on the Commencement Date and end on the first October 31 that follows such date;

"**cricondentherm hydrocarbon dewpoint**" shall mean the highest hydrocarbon dewpoint temperature on the phase envelope;

"**cubic metre**" shall mean the volume of gas which occupies one cubic metre when such gas is at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Day**" shall mean a period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time. The reference date for any Day shall be the calendar date upon which the twenty-four (24) hour period shall commence;

"**delivery**" shall mean any gas that is delivered by Union into Shipper's possession, or to the possession of Shipper's agent;

"Eastern Clock Time" shall mean the local clock time in the Eastern Time Zone on any Day;

"**Expansion Facilities**" shall mean any new facilities to be constructed by Union in order to provide Transportation Services;

"**firm**" shall mean service not subject to curtailment or interruption except under Articles XI, XII and XVIII herein;

"**gas**" shall mean gas as defined in the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Sch. B, as amended, supplemented or re-enacted from time to time;

"**gross heating value**" shall mean the total heat expressed in megajoules per cubic metre (MJ/m^3) produced by the complete combustion at constant pressure of one (1) cubic metre of gas with air, with the gas free of water vapour and the temperature of the gas, air and products of combustion at standard temperature and all water formed by the combustion reaction condensed to the liquid state;

"**hydrocarbon dewpoint**" shall mean temperature at a specific pressure where hydrocarbon vapour condensation begins;

"**Interruptible Service HUB Contract**" shall mean a contract between Shipper and Union under which Union provides interruptible HUB service;

"**interruptible service**" or "**Interruptible**" shall mean service subject to curtailment or interruption, after notice, at any time;

"**Interconnecting Pipeline**" shall mean a pipeline that directly connects to the Union pipeline system;

"**joule**" (J) shall mean the work done when the point of application of a force of one (1) newton is displaced a distance of one (1) metre in the direction of the force. The term "**megajoule**" (MJ) shall mean 1,000,000 joules. The term "**gigajoule**" (GJ) shall mean 1,000,000,000 joules;

"Loaned Quantities" shall mean those quantities of gas loaned to Shipper under the Facilitating Agreement;

"**m³**" shall mean cubic metre of gas and "10^3m^3" shall mean 1,000 cubic metres of gas;

"**Month**" shall mean the period beginning at 10:00 a.m. Eastern Clock Time on the first day of a calendar month and ending at 10:00 a.m. Eastern Clock Time on the first day of the following calendar month;

"**NAESB**" shall mean North American Energy Standards Board;

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

"**Open Season**" or "**open season**" shall mean an open access auction or bidding process held by Union as a method of allocating capacity;

"**pascal**" (Pa) shall mean the pressure produced when a force of one (1) newton is applied to an area of one (1) square metre. The term "kilopascal" (kPa) shall mean 1,000 pascals;

"**receipt**" shall mean any gas that is delivered into Union's possession, or the possession of Union's agent;

"**Shipper**" shall have the meaning as defined in the Contract, and shall also include Shipper's agent(s);

"**specific gravity**" shall mean density of the gas divided by density of air, with both at a temperature of 15 degrees Celsius, and at a pressure of 101.325 kilopascals absolute;

"**Taxes**" shall mean any tax (other than tax on income or tax on property), duty, royalty, levy, license, fee or charge not included in the charges and rates as per the applicable rate schedule (including but not limited to charges under any form of cap and trade, carbon tax, or similar system) and that is levied, assessed or made by any governmental authority on the gas itself, or the act, right, or privilege of producing, severing, gathering, storing, transporting, handling, selling or delivering gas under the Contract;

"**TCPL**" means TransCanada PipeLines Limited;

"**Wobbe Number**" shall mean gross heating value of the gas divided by the square root of its specific gravity.

II. GAS QUALITY

1. Natural Gas: The minimum gross heating value of the gas delivered to/by Union hereunder, shall be thirty-six (36) megajoules per cubic metre. The maximum gross heating value of the gas delivered to/by Union hereunder shall be forty point two (40.2) megajoules per cubic metre. The gas to be delivered hereunder to Union may be a commingled supply from Shipper's gas sources of supply. The gas to be delivered by Union may be a commingled supply from Union's sources of gas supply; provided, however, that helium, natural gasoline, butane, propane and other hydrocarbons, except methane, may be removed prior to delivery to Shipper. Further, Union may subject, or permit the subjection of, the gas to compression, dehydration, cooling, cleaning and other processes.

2. Freedom from objectionable matter: The gas to be delivered to/by Union hereunder,

   a. shall be commercially free from bacteria, 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 objectionable 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,

b. shall not contain more than seven (7) milligrams of hydrogen sulphide per cubic metre of gas, nor more than four hundred and sixty (460) milligrams of total sulphur per cubic metre of gas,

c. shall not contain more than five (5) milligrams of mercaptan sulphur per cubic metre of gas,

d. shall not contain more than two point zero (2.0) molar percent by volume of carbon dioxide in the gas,

e. shall not contain more than zero point four (0.4) molar percent by volume of oxygen in the gas,

f. shall not contain more than zero point five (0.5) molar percent by volume of carbon monoxide in the gas,

g. shall not contain more than four point zero (4.0) molar percent by volume of hydrogen in the gas,

h. shall not contain more than sixty-five (65) milligrams of water vapour per cubic metre of gas,

i. shall not have a cricondentherm hydrocarbon dewpoint exceeding minus eight (-8) degrees Celsius,

j. shall have Wobbe Number from forty seven point fifty (47.50) megajoules per cubic metre of gas to fifty one point forty six (51.46) megajoules per cubic metre of gas, maximum of one point five (1.5) mole percent by volume of butane plus (C4+) in the gas, and maximum of four point zero (4.0) mole percent by volume of total inerts in the gas in order to be interchangeable with other Interconnecting Pipeline gas.

3. Non-conforming Gas: In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in this Article II.

4. Quality of Gas Received: The quality of the gas to be received by Union hereunder is to be of a merchantable quality and in accordance with the quality standards as set out by Union in this Article II, but, Union will also accept gas of a quality as set out in any other Interconnecting Pipeline's general terms and conditions, provided that all Interconnecting Pipelines accept such quality of gas. In addition to any other right or remedy of a party, each party shall be entitled to refuse to accept delivery of any gas which does not conform to any of the specifications set out in Union's M12 Rate Schedule.

III. MEASUREMENTS

1. Storage, Transportation, and/or Sales Unit: The unit of the gas delivered to Union shall be a megajoule or a gigajoule. The unit of gas transported or stored by Union shall be a megajoule or a gigajoule. The unit of gas delivered by Union shall be a megajoule, a gigajoule, a cubic metre (m^3) or one thousand cubic metres (10^3m^3) at Union's discretion.

2. Determination of Volume and Energy:

a. The volume and energy amounts determined under the Contract shall be determined in accordance with the Electricity and Gas Inspection Act (Canada), RSC 1985, c E-4- (the "**Act**") and the Electricity and Gas Inspection Regulations, SOR 86/131 (the "**Regulations**"), and any documents issued under the authority of the Act and Regulations and any amendments thereto.

b. The supercompressibility factor shall be determined in accordance with either the "Manual for Determination of Supercompressibility Factors for Natural Gas" (PAR Project NX-19) published in 1962 or with American Gas Association Transmission Measurement Committee Report No. 8, Nov. 1992, at Union's discretion, all as amended from time to time.

c. The volume and/or energy of the gas delivered to/by Union hereunder shall be determined by the measurement equipment designated in Article VII herein.

d. Upon request by Union, Shipper shall obtain measurement of the total quantity of gas received by Union hereunder from the Interconnecting Pipeline. Such measurement shall be done in accordance with established practices between Union and the Interconnecting Pipeline.

IV. RECEIPT POINT AND DELIVERY POINT

1. Unless otherwise specified in the Contract, the point or points of receipt and point or points of delivery for all gas to be covered hereunder shall be on the outlet side of the measuring stations located at or near the point or points of connection specified in the Contract, where possession of the gas changes from one party to the other, and as per Schedule "D 2010".

V. POSSESSION OF AND RESPONSIBILITY FOR GAS

1. Possession of Gas: Union accepts no responsibility for any gas prior to such gas being delivered to Union at the Receipt Point or after its delivery by Union at the Delivery Point. As between the parties hereto, Union shall be deemed to be in control and possession of and responsible for all such gas from the time that such gas enters Union's system until such gas is delivered to Shipper.

2. Liability: Shipper agrees that Union is not a common carrier and is not an insurer of Shipper's gas, and that Union shall not be liable to Shipper or any third party for loss of gas in Union's possession, except to the extent such loss is caused entirely by Union's negligence or wilful misconduct.

VI. FACILITIES ON SHIPPER'S PROPERTY

Except under those conditions where Union is delivering to TCPL for TCPL or Shipper at Parkway (TCPL), or to an Interconnecting Pipeline, or where otherwise specified in the Contract, the following will apply:

1. Construction and Maintenance: Union, at its own expense may construct, maintain and operate on Shipper's property at the delivery point a measuring station properly equipped with a meter or meters and any other necessary measuring equipment for properly measuring the gas redelivered under the Contract. Shipper will grant to Union a lease and/or rights-of-way over property of Shipper as required by Union to install such facilities and to connect same to Union's pipeline.

2. Entry: Union, its servants, agents and each of them may at any reasonable time on notice (except in cases of emergency) to Shipper or his duly authorized representative enter Shipper's property for the purpose of constructing, maintaining, removing, operating and/or repairing station equipment.

3. Property: The said station and equipment will be and remain the property of Union notwithstanding it is constructed on and attached to the realty of Shipper, and Union may at its own expense remove it upon termination of the Contract and will do so if so requested by Shipper.

VII. MEASURING EQUIPMENT

1. Metering by Union: Union will install and operate meters and related equipment as required and in accordance with the Act and Regulations referenced in Article III herein.

2. Metering by Others: In the event that all or any gas delivered to/by Union hereunder is measured by a meter that is owned and operated by an Interconnecting Pipeline, then Union and Shipper agree to accept that metering for the purpose of determining the volume and energy of gas delivered to/by Union on behalf of the Shipper. The standard of measurement and tests for the gas delivered to/by Union hereunder shall be in accordance with the general terms and conditions as incorporated in that Interconnecting Pipeline company's gas tariff as approved by its regulatory body.

3. Check Measuring Equipment: Shipper may install, maintain and operate, at the redelivery point, at its own expense, such check measuring equipment as desired, provided that such equipment shall be so installed as not to interfere with the operation of Union's measuring equipment at or near the delivery point, and shall be installed, maintained and operated in conformity with the same standards and specifications applicable to Union's metering facilities.

4. Rights of Parties: The measuring equipment installed by either party, together with any building erected by it for such equipment, shall be and remain its property. However, Union and Shipper shall have the right to have representatives present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the other's measuring equipment used in measuring or checking the measurement of deliveries of gas to/by Union under the Contract. Either party will give the other party reasonable notice of its intention to carry out the acts herein specified. The records from such measuring equipment shall remain the property of their owner, but upon request each will submit to the other its records and charts, together with calculations therefrom, for inspection and verification, subject to return within ten (10) days after receipt thereof.

5. Calibration and Test of Measuring Equipment: The accuracy of Union's measuring equipment shall be verified by Union at reasonable intervals, and if requested, in the presence of representatives of Shipper, but Union shall not be required to verify the accuracy of such equipment more frequently than once in any thirty (30) day period. In the event either party notifies the other that it desires a special test of any measuring equipment, the parties shall co-operate to secure a prompt verification of the accuracy of such equipment. The expense of any such special test, if called for by Shipper, shall be borne by Shipper if the measuring equipment tested is found to be in error by not more than two per cent (2%). If, upon test, any measuring equipment is found to be in error by not more than two per cent (2%), previous recordings of such equipment shall be considered accurate in computing receipts and deliveries of gas, but such equipment shall be adjusted at once to record as near to absolute accuracy as possible. If the test conducted shows a percentage of inaccuracy greater than two percent (2%), the financial adjustment, if any, shall be calculated in accordance with the Act and Regulations, as may be amended from time to time and in accordance with any successor statutes and regulations.

6. Preservation of Metering Records: Union and Shipper shall each preserve for a period of at least six (6) years all test data, and other relevant records.

7. Error in Metering or Meter Failure: In the event of an error in metering or a meter failure, (such error or failure being determined through check measurement by Union or any other available method), then Shipper shall enforce its rights as Shipper with the Interconnecting Pipeline(s) to remedy such error or failure including enforcing any inspection and/or verification rights and procedures.

VIII. BILLING

1. Monthly Billing Date: Union shall render bills on or before the tenth (10^{th}) day of each month for all Transportation Services furnished during the preceding Month. Such charges may be based on estimated quantities, if actual quantities are unavailable in time to prepare the billing. Union shall provide, in a succeeding Month's billing, an adjustment based on any difference between actual quantities and estimated quantities, without any interest charge. If presentation of a bill to Shipper is delayed after the tenth (10^{th}) day of the month, then the time of payment shall be extended accordingly, unless Shipper is responsible for such delay.

2. Right of Examination: Both Union and Shipper shall have the right to examine at any reasonable time the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, chart or computation made under or pursuant to the provisions of the Contract.

3. Amendment of Statements: For the purpose of completing a final determination of the actual quantities of gas handled in any of the Transportation Services to Shipper, the parties shall have the right to amend their statement for a period equal to the time during which the Interconnecting Pipeline retains the right to amend their statements, which period shall not exceed three (3) years from the date of termination of the Contract.

IX. PAYMENTS

1. Monthly Payments: Shipper shall pay the invoiced amount directly into Union's bank account as directed on the invoice on or before the twentieth (20^{th}) day of each month. If the payment date is not a Business Day, then payment must be received in Union's account on the first Business Day preceding the twentieth (20th) day of the month.

2. Remedies for Non-payment: Should Shipper fail to pay all of the amount of any bill as herein provided when such amount is due,

a. Shipper shall pay to Union interest on the unpaid portion of the bill accruing at a rate per annum equal to the minimum commercial lending rate of Union's principal banker in effect from time to time from the due date until the date of payment; and,

b. If such failure to pay continues for thirty (30) days after payment is due, Union, in addition to any other remedy it may have under the Contract, may suspend Services until such amount is paid. Notwithstanding such suspension, all demand charges shall continue to accrue hereunder as if such suspension were not in place.

If Shipper in good faith disputes the amount of any such bill or part thereof Shipper shall pay to Union such amounts as it concedes to be correct. At any time thereafter, within twenty (20) days of a demand made by Union, Shipper shall furnish financial assurances satisfactory to Union, guaranteeing payment to Union of the amount ultimately found due upon such bill after a final determination. Such a final determination may be reached either by agreement, arbitration decision or judgement of the courts, as may be the case. Union shall not be entitled to suspend Services because of such non-payment unless and until default occurs in the conditions of such financial assurances or default occurs in payment of any other amount due to Union hereunder.

Notwithstanding the foregoing, Shipper is not relieved from the obligation to continue its deliveries of gas to Union under the terms of any agreement, where Shipper has contracted to deliver specified quantities of gas to Union.

3. Billing Adjustments: If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions of the Contract and Shipper shall have actually paid the bills containing such overcharge or undercharge, Union shall refund the amount of any such overcharge and interest shall accrue from and including the first day of such overcharge as paid to the date of refund and shall be calculated but not compounded at a rate per annum determined each day during the calculation period to be equal to the minimum commercial lending rate of Union's principal banker, and the Shipper shall pay the amount of any such undercharge, but without interest. In the event Union renders a bill to Shipper based upon measurement estimates, the required adjustment to reflect actual measurement shall be made on the bill next following the determination of such actual measurement, without any charge of interest. In the event an error is discovered in the amount billed in any statement rendered by Union, such error shall be adjusted by Union. Such overcharge, undercharge or error shall be adjusted by Union on the bill next following its determination (where the term "**bill next following**" shall mean a bill rendered at least fourteen (14) days after the day of its determination), provided that claim therefore shall have been made within three (3) years from the date of the incorrect billing. In the event any refund is issued with Shipper's bill, the aforesaid date of refund shall be deemed to be the date of the issue of bill.

4. Taxes: In addition to the charges and rates as per the applicable rate schedules and price schedules, Shipper shall pay all Taxes which are imposed currently or subsequent to the execution of the Contract by any legal authority having jurisdiction and any amount in lieu of such Taxes paid or payable by Union.

5. Set Off: If either party shall, at any time, be in arrears under any of its payment obligations to the other party under the Contract, then the party not in arrears shall be entitled to reduce the amount payable by it to the other party in arrears under the Contract, or any other contract, by an amount equal to the amount of such arrears or other indebtedness to the other party. In addition to the foregoing remedy, Union may, upon forty-eight (48) hours verbal notice, to be followed by written notice, take possession of any or all of Shipper's gas under the Contract or any enhancement to the Contract, which shall be deemed to have been assigned to Union, to reduce such arrears or other indebtedness to Union.

X. ARBITRATION

If and when any dispute, difference or question shall arise between the parties hereto touching the Contract or anything herein contained, or the construction hereof, or the rights, duties or liabilities of the parties in relation to any matter hereunder, the matter in dispute shall be submitted and referred to arbitration within ten (10) days after written request of either party. Upon such request each party shall appoint an arbitrator, and the two so appointed shall appoint a third. A majority decision of the arbitrators shall be final and binding upon both parties. In all other respects the provisions of the Arbitration Act, 1991, or any act passed in amendment thereof or substitution therefore, shall apply to each such submission. Operations under the Contract shall continue, without prejudice, during any such arbitration and the costs attributable to such arbitration shall be shared equally by the parties hereto.

XI. FORCE MAJEURE

1. Definition: The term "**force majeure**" as used herein shall mean acts of God, strikes, lockouts or any other industrial disturbance, acts of the public enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing of wells or lines of pipe, inability to obtain materials, supplies, permits or labour, any laws, orders, rules, regulations, acts or restraints of any governmental body or authority (civil or military), any act or omission that is excused by any event or occurrence of the character herein defined as constituting force majeure, any act or omission by parties not controlled by the party having the difficulty and any other similar cases not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome.

2. Notice: In the event that either the Shipper or Union is rendered unable, in whole or in part, by force majeure, to perform or comply with any obligation or condition of the Contract, such party shall give notice and full particulars of such force majeure in writing delivered by hand, fax or other direct written electronic means to the other party as soon as possible after the occurrence of the cause relied on and subject to the provision of this Article.

3. Exclusions: Neither party shall be entitled to the benefit of the provisions of force majeure hereunder if any or all of the following circumstances prevail: the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension; 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); the party claiming suspension failed to resume the performance of such condition obligations with reasonable dispatch; the failure was caused by lack of funds; the party claiming suspension did not, as soon as possible after determining, or within a period within which it should acting reasonably have determined, 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, give to the other party the notice required hereunder.

4. Notice of Remedy: The party claiming suspension shall likewise give notice as soon as possible after the force majeure condition is remedied, to the extent that the same has been remedied, and that such party has resumed or is then in a position to resume the performance of the obligations and conditions of the Contract.

5. Obligation to Perform: An event of force majeure on Union's system will excuse the failure to deliver gas by Union or the failure to accept gas by Union hereunder, and both parties shall be excused from performance of their obligations hereunder, except for payment obligations, to the extent of and for the duration of the force majeure.

6. Upstream or Downstream Force Majeure: An event of force majeure upstream or downstream of Union's system shall not relieve Shipper of any payment obligations.

7. Delay of Firm Transportation Services: Despite Article XI herein, if Union is prevented, by reason of an event of force majeure on Union's system from delivering gas on the Day or Days upon which Union has accepted gas from Shipper, Union shall thereafter make all reasonable efforts to deliver such quantities as soon as practicable and on such Day or Days as are agreed to by Shipper and Union. If Union accepts such gas on this basis, Shipper shall not receive any demand charge relief as contemplated under Article XI herein.

8. Demand Charge Relief for Firm Transportation Services: Despite Article XI herein, if on any Day Union fails to accept gas from Shipper by reason of an event of force majeure on Union's system and fails to deliver the quantity of gas nominated hereunder by Shipper up to the firm Contract Demand for that Contract, then for that Day the Monthly demand charge shall be reduced by an amount equal to the applicable Daily Demand Rate, as defined in this paragraph, multiplied by the difference between the quantity of gas actually delivered by Union during such Day and the quantity of gas which Shipper in good faith nominated on such Day. The term "**Daily Demand Rate**" shall mean the Monthly demand charge or equivalent pursuant to the M12 Rate Schedule divided by the number of days in the month for which such rate is being calculated.

9. Proration of Firm Transportation Service: If, due to the occurrence of an event of force majeure as outlined above, the capacity for gas deliveries by Union is impaired, it will be necessary for Union to curtail Shipper's gas receipts to Union hereunder, via proration based on utilization of such facilities for the Day. This prorating shall be determined by

multiplying the capability of such facilities as available downstream of the impairment on the Day, by a fraction where the numerator is Shipper's nominated firm quantity and the denominator is the total of all such nominated firm quantities for nominated services and planned consumption for in-franchise customers on the Day. For the purposes of this Article XI, firm services shall mean all firm services provided by Union to in-franchise customers and ex-franchise shippers.

XII. DEFAULT AND TERMINATION

In case of the breach or non-observance or non-performance on the part of either party hereto of any covenant, proviso, condition, restriction or stipulation contained in the Contract (but not including herein failure to take or make delivery in whole or in part of the gas delivered to/by Union hereunder occasioned by any of the reasons provided for in Article XI herein) which has not been waived by the other party, then and in every such case and as often as the same may happen, the non-defaulting party may give written notice to the defaulting party requiring it to remedy such default and in the event of the defaulting party failing to remedy the same within a period of thirty (30) days from receipt of such notice, the non-defaulting party may at its sole option declare the Contract to be terminated and thereupon the Contract shall be terminated and be null and void for all purposes other than and except as to any liability of the parties under the same incurred before and subsisting as of termination. The right hereby conferred upon each party shall be in addition to, and not in derogation of or in substitution for, any other right or remedy which the parties respectively at law or in equity shall or may possess.

XIII. AMENDMENT

Subject to Article XV herein and the ability of Union to amend the applicable rate schedules and price schedules, with the approval of the OEB (if required), no amendment or modification of the Contract shall be effective unless the same shall be in writing and signed by each of the Shipper and Union.

XIV. NON-WAIVER AND FUTURE DEFAULT

No waiver of any provision of the Contract shall be effective unless the same shall be in writing and signed by the party entitled to the benefit of such provision and then such waiver shall be effective only in the specific instance and for the specified purpose for which it was given. No failure on the part of Shipper or Union to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under the Contract shall operate as a waiver thereof.

XV. LAWS, REGULATIONS AND ORDERS

The Contract and the respective rights and obligations of the parties hereto are subject to all present and future valid laws, orders, rules and regulations of any competent legislative body, or duly constituted authority now or hereafter having jurisdiction and the Contract shall be varied and amended to comply with or conform to any valid order or direction of any board, tribunal or administrative agency which affects any of the provisions of the Contract.

XVI ALLOCATION OF CAPACITY

1. Requests for Transportation Service: A potential shipper may request firm transportation service on Union’s system at any time. Any request for firm M12 transportation service must include: potential shipper’s legal name, Receipt Point(s), Delivery Point(s), Commencement Date, Initial Term, Contract Demand and proposed payment. This is applicable for M12 service requests for firm transportation service with minimum terms of ten (10) years where Expansion Facilities are required or a minimum term of five (5) years for use of existing capacity.

2. Expansion Facilities: If requests for firm transportation services cannot be met through existing capacity such that the only way to satisfy the requests for transportation service would require the construction of Expansion Facilities which create new capacity, Union shall allocate any such new capacity by open season, subject to the terms of the open season, and these General Terms and Conditions.

3. <u>Open Seasons:</u> If requests for long-term firm transportation service can be met through existing facilities upon which long-term capacity is becoming available, Union shall allocate such long-term capacity by open season, subject to the terms of the open season, and these General Terms and Conditions. "**Long-term**", for the purposes of this Article XVI, means, in the case of a transportation service, a service that has a term of one year or greater.

4. <u>Awarding Open Season Capacity:</u> Capacity requests received during an open season shall be awarded starting with those bids with the highest economic value. If the economic values of two or more independent bids are equal, then service shall be allocated on a pro-rata basis. The economic value shall be based on the net present value which shall be calculated based on the proposed per- unit rate and the proposed term of the contract and without regard to the proposed Contract Demand ("**NPV**").

5. <u>Available Capacity Previously Offered in Open Season:</u> Union may at any time allocate capacity to respond to any M12 transportation service request through an open season. If a potential shipper requests M12 transportation service that can be provided through Available Capacity that was previously offered by Union in an open season but was not awarded, then:

   a. Any such request must conform to the requirements of Section 1 of this Article XVI;

   b. Union shall allocate capacity to serve such request pursuant to this Section 5, and subject to these General Terms and Conditions and Union's standard form M12 transportation contract;

   c. Union may reject a request for M12 transportation service for any of the following reasons:

      i) if there is insufficient Available Capacity to fully meet the request, but if that is the only reason for rejecting the request for service, Union must offer to supply the Available Capacity to the potential shipper;

      ii) if the proposed monthly payment is less than Union's Monthly demand charge plus fuel requirements for the applicable service;

      iii) if prior to Union accepting the request for transportation service Union receives a request for transportation service from one or more other potential shippers and there is, as a result, insufficient Available Capacity to service all the requests for service, in which case Union shall follow the procedure in Section 5 d hereof; -

      iv) if Union does not provide the type of transportation service requested; or

      v) if all of the conditions precedent specified in Article XXI Sections 1 and 2 herein have not been satisfied or waived.

   d. Union will advise the potential shipper in writing whether Union accepts or rejects the request for service, subject to Article XVI 5 c, within 5 calendar days of receiving a request for M12 transportation service. If Union rejects a request for service, Union shall inform the potential shipper of the reasons why its request is being rejected; and

   e. If Union has insufficient Available Capacity to service all pending requests for transportation service Union may:

      i) Reject all the pending requests for transportation service and conduct an open season; or

      ii) Union shall inform all the potential shippers who have submitted a pending request for transportation service that it does not have sufficient capacity to service all pending requests for service, and Union shall provide all such potential shippers with an equal opportunity to submit a revised request for service. Union shall then allocate the Available Capacity to the request for transportation service with the highest economic value to Union. If the economic values of two or more requests are equal, then service shall be allocated on a pro-rata basis. The economic value of any request shall be based on the NPV.

XVII. <u>RENEWALS</u>

Contracts with an Initial Term of five (5) years or greater will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter. Shipper may reduce the Contract Demand or terminate the Contract with notice in writing by Shipper at least two (2) years prior to the expiration thereof.

XVIII. SERVICE CURTAILMENT

1. Right to Curtail: Union shall have the right to curtail or not to schedule part or all of Transportation Services, in whole or in part, on all or a portion of its pipeline system at any time for reasons of Force Majeure or when, in Union sole discretion, acting reasonably, capacity or operating conditions so require or it is desirable or necessary to make modifications, repairs or operating changes to its pipeline system. Union shall provide Shipper such notice of such curtailment as is reasonable under the circumstances. If due to any cause whatsoever Union is unable to receive or deliver the quantities of Gas which Shipper has requested, then Union shall order curtailment by all Shippers affected and to the extent necessary to remove the effect of the disability. Union has a priority of service policy to determine the order of service curtailment. In order to place services on the priority of service list, Union considers the following business principles: appropriate level of access to core services, customer commitment, encouraging appropriate contracting, materiality, price and term, and promoting and enabling in-franchise consumption.

   The Priority ranking for all services utilizing Union Gas' storage, transmission and distribution system as applied to both in-franchise and ex-franchise services are as follows; with number 1 having the highest priority and the last interrupted.

   1. Firm In-franchise Transportation and Distribution services and firm Ex-franchise services (Note 1)
   2. In-franchise Interruptible Distribution services
   3. C1/M12 IT Transport and IT Exchanges with Take or Pay rates
   4. Balancing (Hub Activity) < = 100 GJ/d; Balancing (Direct Purchase) < = 500 GJ/d; In-franchise distribution authorized overrun (Note 3)
   5. C1/M12 IT Transport and IT Exchanges at premium rates
   6. C1/M12 Overrun < = 20% of CD (Note 4)
   7. Balancing (Direct Purchase) > 500 GJ/d
   8. Balancing (Hub Activity) > 100 GJ/d; C1/M12 IT Transport and IT Exchanges
   9. C1/M12 Overrun > 20% of CD
   10. C1/M12 IT Transport and IT Exchanges at a discount
   11. Late Nominations

   Notes:
   1. Nominated services must be nominated on the NAESB Timely Nomination Cycle otherwise they are considered to be late nomination and are therefore interruptible.
   2. Higher value or more reliable IT is contemplated in the service and contract, when purchase at market competitive prices.
   3. Captures the majority of customers that use Direct Purchase balancing transactions.
   4. Captures the majority of customers that use overrun.

2. Capacity Procedures: Union reserves the right to change its procedures for sharing interruptible capacity and will provide Shipper with two (2) months prior notice of any such change.

3. Maintenance: Union's facilities from time to time may require maintenance or construction. If such maintenance or construction is required, and in Union's sole opinion, acting reasonably, such maintenance or construction may impact Union's ability to meet Shipper's requirements, Union shall provide at least ten (10) days notice to Shipper, except in the case of an emergency. In the event the maintenance impacts Union's ability to meet Shipper's requirements, Union shall not be liable for any damages and shall not be deemed in breach of the Contract. To the extent that Union's ability to accept and/or deliver Shipper's gas is impaired, the Monthly demand charge shall be reduced in accordance with Article XI Section 8 and available capacity allocated in accordance with Article XI Section 9 herein.

   Union shall use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to limit the extent and duration of any impairments. Union will endeavour to schedule and complete the maintenance and construction, which would normally be expected to impact on Union's ability to meet Shipper's requirements, during the period from April 1 through to November 1.

XIX. SHIPPER'S REPRESENTATIONS AND WARRANTIES

1. Shipper's Warranty: Shipper warrants that it will, if required, maintain, or have maintained on its behalf, all external approvals including the governmental, regulatory, import/export permits and other approvals or authorizations that are required from any federal, state or provincial authorities for the gas quantities to be handled under the Contract. Shipper further warrants that it shall maintain in effect the Facilitating Agreements.

2. Financial Representations: Shipper represents and warrants that the financial assurances (including the Initial Financial Assurances and Security) (if any) shall remain in place throughout the term hereof, unless Shipper and Union agree otherwise. Shipper shall notify Union in the event of any change to the financial assurances throughout the term hereof. Should Union have reasonable grounds to believe that Shipper will not be able to perform or continue to perform any of its obligations under the Contract as a result of one of the following events (“**Material Event**”);

   a. Shipper is in default, which default has not been remedied, of the Contract or is in default of any other material contract with Union or another party; or,

   b. Shipper’s corporate or debt rating falls below investment grade according to at least one nationally recognized rating agency; or,

   c. Shipper ceases to be rated by a nationally recognized agency; or,

   d. Shipper has exceeded credit available as determined by Union from time to time,

   then Shipper shall within fourteen (14) days of receipt of written notice by Union, obtain and provide to Union a letter of credit or other security in the form and amount reasonably required by Union (the “**Security**”). The Security plus the Initial Financial Assurances shall not exceed twelve (12) months of Monthly demand charges (in accordance with Article IX herein) multiplied by Contract Demand. In the event that Shipper does not provide to Union such Security within such fourteen (14) day period, Union may deem a default under the Default and Termination provisions of Article XII herein.

   In the event that Shipper in good faith, reasonably believes that it should be entitled to reduce the amount of or value of the Security previously provided, it may request such a reduction from Union and to the extent that the Material Event has been mitigated or eliminated, Union shall return all or a portion of the Security to Shipper within fourteen (14) Business Days after receipt of the request.

XX. MISCELLANEOUS PROVISIONS

1. Permanent Assignment: Shipper may assign the Contract to a third party (“Assignee”), up to the Contract Demand, (the “Capacity Assigned”). Such assignment shall require the prior written consent of Union and release of obligations by Union for the Capacity Assigned from the date of assignment. Such consent and release shall not be unreasonably withheld and shall be conditional upon the Assignee providing, amongst other things, financial assurances as per Article XXI herein. Any such assignment will be for the full rights, obligations and remaining term of the Contract as relates to the Capacity Assigned.

2. Temporary Assignment: Shipper may, upon notice to Union, assign all or a part of its service entitlement under the Contract (the “Assigned Quantity”) and the corresponding rights and obligations to an Assignee on a temporary basis for not less than one calendar month. Such assignment shall not be unreasonably withheld and shall be conditional upon the Assignee executing the Facilitating Agreement as per Article XXI herein. Notwithstanding such assignment, Shipper shall remain obligated to Union to perform and observe the covenants and obligations contained herein in regard to the Assigned Quantity to the extent that Assignee fails to do so.

3. Title to Gas: Shipper represents and warrants to Union that Shipper shall have good and marketable title to, or legal authority to deliver to Union, all gas delivered to Union hereunder. Furthermore, Shipper hereby agrees to indemnify and save Union harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of claims of any or all third parties to such gas or on account of Taxes, or other charges thereon.

XXI. PRECONDITIONS TO TRANSPORTATION SERVICES

1. Union Conditions: The obligations of Union to provide Transportation Services hereunder are subject to the following conditions precedent, which are for the sole benefit of Union and which may be waived or extended in whole or in part in the manner provided in the Contract:

    a. Union shall have obtained, in form and substance satisfactory to Union, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to provide the Transportation Services; and,

    b. Union shall have obtained all internal approvals that are necessary or appropriate to provide the transportation Services; and,

    c. Union shall have received from Shipper the requisite financial assurances reasonably necessary to ensure Shipper's ability to honour the provisions of the Contract (the "**Initial Financial Assurances**"). The Initial Financial Assurances, if required, will be as determined solely by Union; and,

    d. Shipper and Union shall have entered into the Interruptible Service HUB Contract or equivalent (the "**Facilitating Agreement**") with Union.

2. Shipper Conditions: The obligations of Shipper hereunder are subject to the following conditions precedent, which are for the sole benefit of Shipper and which may be waived or extended in whole or in part in the manner provided in the Contract:

    a. Shipper shall, as required, have entered into the necessary contracts with Union and/or others to facilitate the Transportation Services contemplated herein, including contracts for upstream and downstream transportation, and shall specifically have an executed and valid Facilitating Agreement; and shall, as required, have entered into the necessary contracts to purchase the gas quantities handled under the Contract; and,

    b. Shipper shall have obtained, in form and substance satisfactory to Shipper, and all conditions shall have been satisfied under, all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required from federal, state, or provincial authorities for the gas quantities handled under the Contract; and,

    c. Shipper shall have obtained all internal approvals that are necessary or appropriate for the Shipper to execute the Contract.

3. Satisfaction of Conditions: Union and Shipper shall each use due diligence and reasonable efforts to satisfy and fulfil the conditions precedent specified in this Article XXI Section 1 a, c, and d and Section 2 a and b. Each party shall notify the other forthwith in writing of the satisfaction or waiver of each condition precedent for such party's benefit. If a party concludes that it will not be able to satisfy a condition precedent that is for its benefit, such party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations thereunder.

4. Non-Satisfaction of Conditions: If any of the conditions precedent in this Article XXI Section 1 c or Section 2 are not satisfied or waived by the party entitled to the benefit of that condition by the Conditions Date as such term is defined in the Contract, then either party may, upon written notice to the other party, terminate the Contract and upon the giving of such notice, the Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of the Contract prior to such termination and any liability a party may have incurred before such termination shall not thereby be released.

4-STAFF-44

Reference: **Exhibit 1 / Tab 1 / Schedule 1/ Pg. 25 and Exhibit 4 / Tab 1 / Schedule 1/ Pg.6**

Request:

In the list of approvals requested, EPCOR is seeking approval to continue to purchase one million cubic meters of gas annually at a rate of $8.486 per mcf. from On-Energy Corp. until September 30, 2020. In Exhibit 4 of the application (Tab1,Sch 1, Pg.6), EPCOR has proposed that it continue to recover from ratepayers $8.486 per mcf. for the first one million cubic meters of gas purchased from On-Energy Corp. until September 20, 2020.

Please reconcile the two dates and confirm the approval that is being requested.

Response:

EPCOR is seeking approval to continue to purchase and recover from system gas customers one million cubic meters of gas annually at a rate of $8.486 per mcf from On-Energy Corp. until the end of the term of the current gas purchase agreement, September 30, 2020, as requested in Exhibit 1, Tab 1, Schedule 1. The incorrect date was inadvertently quoted in Exhibit 4.

4-STAFF-45

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pg. 6 and OEB Decision and Order EB-2010-0018, Phase 2, May 17, 2012**

Request:

In the EB-2010-0018 Phase 2 Decision, the OEB permitted NRG to purchase a maximum annual quantity of 1.0 million cubic meters of natural gas at a rate of $8.486 per mcf. This rate is higher than market rates. EPCOR has submitted a system integrity study by Cornerstone Energy Services that shows low system pressure in the southern and southeastern part of the distribution system during peak demand. EPCOR has proposed solutions (capital projects) that is expected to eliminate the requirement to purchase gas at other than market rates. EPCOR expects this solution to be in place in advance of the Gas Purchase Agreement expiring on September 20, 2020.

(a) Please confirm that the proposed solutions referred to in the evidence will be in service by December 31, 2019.

(b) Can EPCOR amend the terms of the Gas Purchase Agreement to terminate the purchase of one million cubic meters at a premium as of January 1, 2020?

(c) In the opinion of Cornerstone, does the southern and southeastern part of the distribution system experience low pressure during the summer and shoulder months, specifically, May, June, July, August and September? Please explain your response.

(d) Please provide the quantities of system integrity gas purchased (at a premium) in the above referenced months for each of the years 2013 to 2018.

Response:

(a) Confirmed. ENGLP expects to have the Belmont Reinforcement Project and the Lakeview Reinforcement Project in service by December 31, 2019.

(b) The term of the Gas Purchase Agreement is to September 30, 2020 and does not contain any provisions that permit unilateral amendment by EPCOR. The agreement permits termination by either party in customary circumstances, such as bankruptcy/insolvency or a material breach of the agreement, but EPCOR does not otherwise have a right to unilaterally terminate the agreement.

(c) Under the scope of the system integrity study, Cornerstone's modelling and analysis focussed on periods of peak demand, typically observed in late fall, during agricultural crop drying season, or winter. Cornerstone did not model the distribution system under conditions representative of the summer or shoulder months.

(d) Table 4-STAFF-45-1 below sets out the quantities of local gas purchased (in m^3) between 2013 to 2018 at a price of $8.486/Mcf.

Table 4-STAFF-45-1
2013-2018 Quantities of Gas Purchased
(m^3)

		A	B	C	D	E
	Year	**May**	**June**	**July**	**August**	**September**
1	2013	84,931	82,192	84,931	84,931	82,192
2	2014	84,931	82,192	84,931	84,931	82,192
3	2015	84,931	82,192	84,931	84,931	82,192
4	2016	71,066	-	-	123,655	41,576
5	2017	84,932	82,192	82,192	82,192	87,671
6	2018	84,932	82,192	84,931	84,932	82,192

4-STAFF-46

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 7-8**

Request:

EPCOR has provided the calculated Unaccounted for Gas (UFG) as reported by NRG from 2013 to 2017 which shows a negative variance (higher gas deliveries into the system than consumption). In this application, EPCOR is seeking a UFG of 0% but has also proposed to establish a variance account to record the cost of gas associated with volumetric variances between the actual volume of UFG and the proposed deemed UFG of 0%. This will allow for the recovery of the cost of gas if the actual values vary from the 0% used in establishing rates.

(a) Did NRG undertake any study to determine the contributing factors to UFG? If yes, please provide the study.

(b) Does EPCOR plan to complete a UFG study for the next cost of service application?

(c) Will the variance account be symmetrical, in the sense that it will provide a credit to ratepayers if gas deliveries into the system are lower than gas consumption?

(d) What measures will EPCOR implement to reduce the level of UFG during the IRM period (2020-2024)?

Response:

(a) ENGLP understands that Natural Resource Gas Limited (“NRG”) did not undertake any studies related to UFG.

(b) ENGLP will complete a review of UFG before the next cost of service application. As outlined in paragraph 12 of Section 4.2 (Exhibit 4, Tab 1, Schedule 1), ENGLP notes that there are a number of potential sources of UFG including ‘Operational UFG’ and ‘Accounting UFG’. As a first step, ENGLP intends to review available data to ascertain likely sources of UFG. As an example, ENGLP notes that in April of 2017 NRG implemented a new billing system which may have introduced new or eliminated prior existing Accounting UFG. A bigger data set under the new billing system may be needed in order to assess whether it has had any effect on UFG. Once an initial review of UFG has been completed, ENGLP will determine next steps, including a more formal study, in regards to further defining the source(s) of any UFG.

(c) Yes, the proposed variance account will be symmetrical in the sense that it will provide a credit to ratepayers if gas deliveries into the system are lower than gas consumption.

(d) Once ENGLP better understands the specific drivers giving rise to UFG for the Aylmer operation as informed by the information obtained in its review of UFG outlined in (b) above, ENGLP will identify and plan for the implementation of cost effective measures to reduce the level of UFG.

4-STAFF-47
Reference: Exhibit 4 / Tab 1 / Schedule 1/ Pg. 14

Request:

Table 4.3.2-2 provides the historical year over year change for the 2011 to 2017 period. Please provide a similar table with the actual incurred amounts (as compared to change year over year) for each of the years.

Response:

See Table 4-STAFF-47-1 below.

Table 4-STAFF-47-1
OM&A Actual Costs 2011-2017
($)

		A	B	C	D	E	F	G
	OM&A[1,2]	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**
1	Salaries and Wages	925,255	1,273,349	1,248,464	1,308,204	1,363,587	1,467,592	1,260,108
2	Benefits	122,813	153,383	150,747	145,454	150,112	168,773	151,568
3	Salary Transfers	(52,198)	(83,519)	(63,511)	(76,811)	(72,675)	(75,000)	(75,000)
4	Insurance	277,066	285,902	274,243	164,744	174,538	179,774	169,301
5	Utilities	11,199	9,832	11,043	9,825	10,765	11,900	9,525
6	Advertising	43,906	65,336	56,243	47,948	54,432	65,529	35,082
7	Telephone	39,565	30,017	28,282	26,839	28,444	29,900	27,596
8	Office & Postage	99,383	101,115	107,600	115,485	130,398	133,000	118,430
9	Repair & Maintenance	143,067	158,552	163,360	155,983	186,338	219,780	106,204
10	Automotive	53,463	68,809	61,378	81,090	65,516	72,000	57,628
11	Dues & Fees	29,418	61,976	47,912	34,255	34,835	35,880	18,007
12	Mapping Expense	-	-	-	-	-	-	-
13	Regulatory	278,576	246,479	400,906	1,036,973	225,356	213,500	63,010
14	Bad Debts	32,400	200	29,689	32,034	37,166	40,000	24,594
15	Interest - Security Deposits	1,879	2,778	1,099	2,298	-4,831	2,000	865
16	Bank Charges	48,840	26,202	18,764	20,319	14,908	18,500	34,419
17	Collection Expense	8,008	8,352	7,017	11,408	7,942	8,800	4,847
18	Travel & Ent.	3,328	3,800	3,207	6,146	8,210	9,000	3,525
19	Legal	25,165	2,304	14,465	15,945	205,339	295,000	985,130
20	Audit	15,975	26,772	18,000	19,750	18,000	33,000	24,000
21	Consulting Fees	37,675	46,216	44,684	53,441	40,181	100,000	3,490
22	Management Fees	457,020	457,020	457,020	457,020	457,020	457,020	457,020
23	Correction on CCA issue	-	-	-	-	-	-	-
24	Miscellaneous	-	-	-	-	-	-	-
25	**Total**	**2,601,803**	**2,944,875**	**3,080,612**	**3,668,350**	**3,135,581**	**3,485,948**	**3,479,349**

[1] Rows 1 to 3 are also provided in Employee Compensation Table 4.3.3.1-1 of the Application
[2] Rows 4 to 24 are also provided in Operating Support Costs Table 4.3.3.2-2 of the Application

4-STAFF-48

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 18-20**

Request:

Since acquiring the assets of NRG, EPCOR has revised the compensation strategy for the utility, targeting the mid-market or 50th percentile of a defined peer group for total employee compensation.

In Table 4.3.3.1-1, EPCOR has provided a breakdown of compensation from 2011 to 2020.

Benefits show a significant increase in 2019 and 2020, rising from approximately $151,000 in 2017 to $362,000 in 2020. There is also an additional payment in the form of an Incentive Plan that did not exist prior to 2018.

(a) Please explain the significant increase in the cost of Benefits and the main drivers of the increased costs.

(b) Are all EPCOR employees eligible for Incentive Plan payments?

(c) Please explain how the compensation strategy of EPCOR will contribute to the operational efficiency of the utility.

Response:

(a) As described in paragraph 53 of Section 4.3.3.1 (Exhibit 4, Tab 1, Schedule 1), the main drivers for the increases in the cost of benefits are the increase in employee salaries from the market adjustments to bring ENGLP Aylmer employees to market salary compensation (as reflected in Table 4.3.3.1-2) and benefits such as the Group RRSP and employee savings plan (employer matches employees' contributions up to 5%).

(b) Yes, all permanent EPCOR Utilities Inc. (EUI or EPCOR) employees are eligible for Incentive Plan payments.

(c) As described in paragraph 40 of Section 4.3.3.1 (Exhibit 4, Tab 1, Schedule 1), EPCOR's compensation philosophy targets the "mid-market" or 50th percentile of a defined peer group for total employee compensation. Paying too much could harm ENGLP's overall competitiveness. Paying too little could make it difficult to recruit new employees and could create employee dissatisfaction, which with a relatively small team in ENGLP Aylmer could have a significant impact on its operations and its customers. Further, if ENGLP's employee compensation is not market competitive, then it may not be able to attract and maintain employees with the necessary skills and training which may affect the operational efficiency of ENGLP, as employees would not have the proper skills to complete work in a safe, timely and accurate manner (i.e., minimize re-work).

4-STAFF-49

Reference: **Exhibit 4/ Tab 1/ Schedule 1/Pg. 20 – Table 4.3.3.1-1**
Exhibit 2/ Tab 1/ Schedule 1/Pg. 16

Request:

From table 4.3.3.1-1, transfers to capital increased from $42,000 to $349,000 from 2011 to 2020.

(a) Please provide a breakdown of the OM&A capitalized from 2011 to 2020 where possible (e.g. employee benefits, cost of site preparation, professional fees etc.)

(b) Please provide a table showing the calculation of the percentage of OM&A capitalized (i.e. OM&A capitalized as a percentage of total OM&A before capitalization) from 2011 to 2020.

(c) Please provide a table showing the OM&A capitalized compared to new capital additions from 2011 to 2020.

(d) In Exhibit 2, EPCOR notes that it is of the view that implementation of capitalization procedures and policies will not have a material impact on the revenue requirement of the utility. Please explain how EPCOR came to this conclusion and provide any analysis that was performed.

Response:

(a) EPCOR cannot confirm NRG's capitalization procedures and policies and given the limited historical financial records EPCOR is unable to provide a breakdown of the capitalized OM&A amounts for 2011 to 2017. The table below provides a breakdown of the OM&A capitalized amounts for 2018 to 2020.

Table 4-STAFF-49-1
2018-2020 Capitalized OM&A Amounts
($ dollars)

		A **2018 A**	B **2019 Bridge Year**	C **2020 Test Year**
1	Salary Transfers	244,115	222,606	222,606
2	Capitalized Overhead	135,668	126,441	126,441
3	**Total**	**379,782**	**349,047**	**349,047**

(b) See the table below for the calculation of the percentage of OM&A capitalized:

Table 4-STAFF-49-2
2018-2020 OM&A % Capitalized
($)

		A **2011 A**	B **2012 A**	C **2013 A**	D **2014 A**	E **2015 A**	F **2016 A**	G **2017 A**	H **2018 A**	I **2019 Bridge Year**	J **2020 Test Year**
1	Salary Transfers[1]	52.2	83.5	63.5	76.8	72.7	75.0	75.0	379.8	349.0	349.0
2	**Total**	**52.2**	**83.5**	**63.5**	**76.8**	**72.7**	**75.0**	**75.0**	**379.8**	**349.0**	**349.0**
3	OM&A[2]	2,601.8	2,944.9	3,080.6	3,668.4	3,135.6	3,485.9	3,479.3	4,120.8	3,244.2	3,359.1
4	Capitalized Costs per above	52.2	83.5	63.5	76.8	72.7	75.0	75.0	379.8	349.0	349.0
5	**Total**	**2,654.0**	**3,028.4**	**3,144.1**	**3,745.2**	**3,208.3**	**3,560.9**	**3,554.3**	**4,500.6**	**3,593.2**	**3,708.1**
6	% of OM&A Capitalized	2.0%	2.8%	2.0%	2.1%	2.3%	2.1%	2.1%	8.4%	9.7%	9.4%
7	Capital Additions[3]	815.2	963.7	1,133.8	842.7	794.1	2,792.8	1,438.7	2,252.6	3,619.8	1,345.6
8	% of OM&A Capitalized versus Capital Additions	6.4%	8.7%	5.6%	9.1%	9.2%	2.7%	5.2%	16.9%	9.6%	25.9%

[1] Amounts per Table 4.3.3.1-1.
[2] Amounts per Table 4.3.1-1. Note that the 2018 OM&A amounts have been updated to actual.
[3] Amounts per Table 2.2.1-3. Note that the 2018 Capital additions have been updated to actual.

(c) See ENGLP's response to (b) above.

(d) EPCOR's capitalization policy should not have a material impact on the revenue requirement based on the amounts expected to be capitalized. EPCOR will appropriately capture and capitalize time spent by staff who are working on capital projects and will include associated overhead. EPCOR notes that net capital additions provided in Table 2.5-1 (Exhibit 2, Tab 1, Schedule 1) show that normal year capital additions for forecast periods are roughly in-line with historical capital additions, adjusted for inflation.

4-STAFF-50

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pg. 21**

Request:

For the 2020 Test Year, EPCOR is proposing to maintain its current complement of 17.5 FTEs. EPCOR intends to hire one senior advisor to identify energy industry trends in the gas supply markets with the aim to decrease costs and inefficiencies related to system fuel gas supply and local production. In addition, the position would be responsible for direct purchase contract management including ensuring accurate and complete forecasting.

(a) Please explain why EPCOR needs a senior advisor to identify energy industry trends in the gas supply markets considering that EPCOR is a system sales customer of Enbridge Gas and acquires over 90% of its requirement under the M9 rate.

(b) How will the senior advisor decrease gas supply costs under a system sales scenario? Please provide a detailed response.

(c) Can EPCOR quantify the benefits that the senior advisor will provide that would justify the related compensation?

(d) Is there an individual in the organization that is currently responsible for direct purchase contract management?

(e) What percentage of EPCOR customers are on direct purchase as compared to system sales?

(f) What kind of forecasting is required for direct purchase contract management?

(g) Assuming a contract is signed with a local producer and the remaining supply is from Enbridge Gas, what tasks would the senior advisor need to perform on a daily basis with respect to contracting or gas supply related issues?

Response:

(a) ENGLP relies on its M9 contract with Enbridge Gas for storage, load balancing and transportation and given its limited size and resources ENGLP plans to continue its strategy of contracting with Enbridge Gas for the majority of its system supply. However, in order to address system integrity and pressure issues, local production will be required to augment Enbridge Gas' system supply in order to ensure reliability of the ENGLP system.

The Senior Advisor will play a role in determining the appropriate mix between supply from Enbridge Gas, direct purchase customers and local production based on its demand forecast and expected annual load profile over the next five years. This involves conducting analysis on peak day forecasts for the current year and each subsequent year and tying it back into the forecast assumptions for annual load. The analysis will help determine how the contract demand will be met on a peak day basis split between the M9 contract and any subsequent local production. Also, sensitivity analysis will need to be conducted to ensure the guiding principles of cost-effectiveness, reliability and security of supply are met.

Further, the Senior Advisor will provide continuous improvement initiatives to the supply planning process to meet the transparency objective of the OEB framework. In order to reliably meet forecasted peak day, seasonal, and annual demand, the Senior Advisor will proactively evaluate new supply and transportation options and identify potential new opportunities to meet ENGLP's gas supply obligations while meeting the OEB Framework Assessment criteria (as discussed in Exhibit 4, Tab 4, Schedule 1, Page 5). This may also include evaluation of Renewable Natural Gas "RNG" as opportunities present themselves.

(b) ENGLP intends to determine prudent options to maintain system integrity and quantify the volume of gas required to alleviate low pressure areas. This aligns with the objectives of the System Integrity Study conducted by Cornerstone on behalf of ENGLP and ensures these objectives are met to address system integrity and low pressure issues. In order to meet these objectives and as noted above, ENGLP continues to be a system gas customer of Enbridge Gas under the M9 rate but also plans to supplement its supply with local production to address future system integrity and pressure issues.

The Senior Advisor will play a role in analyzing contracting for firm local production in an effort to minimize transportation costs on behalf of ENGLP's rate-payers and ensure ENGLP's application of the gas supply planning principles. Supply options can then be chosen by balancing between the principles of reliability and cost-effectiveness to ensure ENGLP customers receive supply at a fair and transparent cost.

In advance of the annual renewal of the contracts with Enbridge Gas (July for IGPC and November for direct purchase and system gas customers), the Senior Advisor will evaluate ENGLP's current demand, forecasted growth and direct purchase demand. This will help establish the annual contract demand with Enbridge Gas under each of the M9 contracts. The Senior Advisor will also consider the amount of local production it is purchasing on both a firm and interruptible basis when establishing its contract demand with Enbridge Gas. The Senior Advisor will find a means of reducing the contract demand with Enbridge Gas and determining an appropriate mix between supply from the Enbridge Gas system and local production at a fair and transparent price and ensuring the appropriate level of demand charges.

Further, the Senior Advisor will monitor and annually review the consumption amounts and patterns of customers in rate classes 3 and 5 to ensure these customers are classified correctly based on their current consumption in relation to the volume requirements and rate class definitions.

(c) Continuous improvement to the supply planning and contract management process is an important element of ENGLP's transparency objective with the OEB framework. The Senior Advisor will play an important part in analyzing the internal processes of the organization and improving initiatives related to forecasting capabilities, contract renewal processes, variance controls, consumption measurement and direct purchase variance reporting. This will ensure documentation and controls are in place for current commercial contract processes and assist in identifying revenue leakage, as well as ensure records and controls are in place pertaining to commodity price change requests by direct marketers.

To summarize, the Senior Advisor's role involves, but is not limited to:

- Conducting supply options analysis, and developing accurate forecasts that inform the analysis (price, weather, demand, consumption patterns etc.).
- Providing an outlook for natural gas market analysis and discussion of future trends.
- Ensuring any supply plan objectives follow the OEB Framework's guiding principles of cost-effectiveness to the rate-payers, reliability and security of supply.

- Streamlining and improving all avenues of direct marketer support, Banked Gas Account ("BGA") /variance and balancing activities.
- Reviewing, identifying and preventing revenue leakage in the commercial contracting processes.
- Assisting ENGLP financial objectives including recognizing unfavorable trends and variances in monthly financial statements and ensuring forecast models created for budgeting are accurate.
- Supporting OEB compliance plans and governance activities such as ensuring accurate reporting of the Federal Carbon Program and its requirements.
- Undertaking continuous improvement initiatives to the supply planning and contract management process and supporting overall ENGLP operations and business objectives.
- Assisting in evaluating and implementing any RNG opportunities as they present themselves.

(d) Prior to the Senior Advisor role, there was no single individual in the organization that was responsible for direct purchase contract management. It was identified that there were opportunities to increase controls, contract compliance and policy and procedures documentation, and for initiatives related to forecasting capabilities, contract renewal processes, consumption measurement, direct purchase variance reporting and to continue to facilitate choices for customers.

Since July 2018, the Senior Advisor has been responsible for streamlining and improving all avenues of direct marketer support, BGA/variance reporting and balancing activities as well as reviewing current commercial contracting processes with the aim of identifying revenue leakage.

(e) Currently, approximately 1.2% of ENGLP customers (including IGPC) are on direct purchase compared to system sales that represent approximately 62% of ENGLP's demand profile by volume.

(f) ENGLP currently has Bundled Transportation contracts for it direct purchase customers as well as the IGPC. Leading into each contract year for these contracts the Senior Advisor will perform analysis as described above in the response to (b) to establish the appropriate contract demand.

Based on current demand, its forecasted growth for the next year, direct purchase demand and unexpected weather changes, the Senior Advisor will provide Enbridge Gas an Obligated Daily Contract Quantity at a Point of Receipt upstream of Enbridge Gas' system. The Senior Advisor will manage the BGA through forecasting its demand requirements and changes in its supply arrangements to achieve a BGA balance of zero at the end of each contract year. Further through ongoing forecasting (based on price, consumption patterns and weather behaviours), the Senior Advisor is expected to take balancing actions early in the winter to ensure that the BGA balance is not less than the Winter Checkpoint Quantity and actions early in the summer to ensure that the BGA balance does not exceed the Fall Checkpoint Quantity. As data is collected throughout the year related to demand, procurement strategies will be evaluated and re-worked based on how actual consumption compares to previously forecasted load and load growth.

4-STAFF-51

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pg. 26**

Request:

EPCOR is forecasting that 25% of each of the General Manager and Administrative & Field Supervisor time will be spent supporting Southern Bruce operations.

(a) Please explain how the 25% allocation was derived.

(b) Will the General Manager and Administrative & Field Supervisor spend 25% of their total time on supporting Southern Bruce operations?

(c) Will the relative size of the Southern Bruce franchise area (when fully connected and operational) be similar to EPCOR Aylmer operations in terms of customer numbers and operating revenue?

(d) How will EPCOR ratepayers benefit during the IR period if EPCOR Aylmer employees provide a much larger support than forecasted for the Southern Bruce operations?

Response:

(a) The 25% allocation was derived based on an estimate of time available for these positions to dedicate to the Southern Bruce operations as well as an estimate of the time required to support the operations. The time was estimated considering the relative size and complexity of the operations. In addition, for the Southern Bruce operation, ENGLP will have project staff on site for a number of years who will undertake certain responsibilities of a General Manager. These include responsibilities related to system expansion, maintenance and connection of customers. These project staff will also be providing supervision to field staff. See (c) below for additional details regarding relative system size.

(b) Yes, ENGLP anticipates the General Manager and Administrative & Field Supervisor will each spend 25% of their total time supporting Southern Bruce operations.

(c) As detailed in ENGLP's Southern Bruce rate application EB-2018-0264 ENGLP is expecting the Southern Bruce operation to be largely connected and operational by the end of 2023 when it is projected to reach 4,887 connections or approximately 93% of the customer connections projected for year 2028. This compares to an estimated 10,421[1] customers for the Aylmer operation in 2023. Southern Bruce would then have approximately 32% of the total customers for the two utilities. In years leading up to 2023 the number of Southern Bruce customers is expected to be substantially less than the 4,887 achieved in 2023. Distribution revenues are expected to be similar for the two operations. However, a direct comparison of distribution revenues is difficult as the Southern Bruce system is new with a resulting higher revenue requirement components including depreciation ($1.136 million for Aylmer in 2020 versus $1.9 million for Southern Bruce in 2028[2]) and return on equity ($0.958 million for Aylmer in 2020 versus $3.0 million for Southern Bruce in 2028). In terms of system size, the Southern Bruce utility is expected to have approximately 298 km of distribution mains as compared to approximately 800 km for the Aylmer operation, with the result that the Southern Bruce operation is approximately 25% of the total for the two utilities.

(d) ENGLP does not expect that ENGLP Aylmer employees will provide more support to the Southern Bruce operations than forecasted in this Application. The construction of the system and development of the Southern Bruce operations will be heavily supported by project resources which will mitigate the need for ENGLP Aylmer resources to provide support beyond the estimated amount. After Southern Bruce has reached a critical mass of customers, the time to support its operations is not expected to be more than estimated considering the size of the operation and the fact that a newly built system would require less capital, maintenance and system planning support than the Aylmer operation.

Further, the ENGLP Aylmer resources are constrained in the amount of support they can provide to the Southern Bruce operation as they have limited available capacity that will

[1] Estimating annual growth at 2.5% starting from the 2020 year end customer count of 9,677.
[2] Using 2028 for Southern Bruce as that is the year in which a revenue requirement has been developed. Values for 2023 would be higher.

not increase over the Price Cap IR term. While ENGLP intends to continue to implement operational efficiencies, efficiencies realised by the Aylmer operation over the Price Cap IR term will be captured in the 0.3% stretch factor proposed by ENGLP as a part of the annual adjustment mechanism in its Price Cap IR Plan outlined in Section 10.1.3 of Exhibit 10, Tab 1, Schedule 1 of the Application.

4-STAFF-52

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pg. 28, 32 and 50-51**

Request:

EPCOR has provided a summary table (4.3.3.2.1-1) for IGPC related operating expenses. The total maintenance costs for the IGPC related assets is $79,672 for 2020. In a subsequent discussion (pg.50), EPCOR notes that the forecasted costs of approximately $80,000 for the contractor within the consulting expense category are mainly for the maintenance of the IGPC regulating station and pipeline infrastructure.

(a) Please explain whether the contractor costs are treated like a pass-through item and forecasted contractor costs are allocated to IGPC without including any additional charges or administrative costs?

(b) In Table 4.3.3.2-2 (Operating Support Costs), EPCOR has separately shown "Repair & Maintenance" and "Consulting Fees". Please confirm that the maintenance costs for IGPC related assets are not included in both categories.

Response:

(a) ENGLP contractor costs are treated like pass-through items and forecasted contractor costs allocated to IGPC does not include any additional charges or costs.

(b) Confirmed. There are no IGPC maintenance costs included in the "consulting fees" category. ENGLP notes that the $80,000 within the consulting expense category is for the contractor to perform Aylmer's meter reading function, and is not related to maintenance costs for IGPC.

Table 4.3.3.2-2 reflects the total operating support costs across the Aylmer operation and the "repair & maintenance" category (row 6) in Table 4.3.3.2-2 includes IGPC maintenance costs. However, per the cost allocation study, ENGLP has removed the IGPC maintenance costs, as identified in Table 4.3.3.2.1-1, from the total "repair & maintenance" costs assigned to Rates 1 through 5 in the cost of service model and direct-assigned these maintenance costs to IGPC.

4-STAFF-53

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 33-50**

Request:

EPCOR's Aylmer operations obtains Shared Services from its affiliate companies EPCOR Water Services Inc. (EWSI), EPCOR Commercial Services Inc. (ECSI), EPCOR Ontario Utilities Inc. (EOUI) and its parent EPCOR Utilities Inc. (EUI). In subsequent discussions, EPCOR has provided various tables that specify the services provided by the affiliate companies and the allocated costs.

Please provide revised tables that indicate what portion of the total costs for each service is allocated to EPCOR Aylmer operations.

Response:

See Table 4-STAFF-53-1 for EWSI, Table 4-STAFF-53-2 for ECSI, Table 4-STAFF-53-3 for EOUI and Tables 4-STAFF-53-4 to 7 for EUI (Corporate Shared Services).

Table 4-STAFF-53-1
EWSI Shared Services Costs Allocated to ENGLP Aylmer 2018-2020
($)

	Shared Service	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EWSI			
1	SCM	970,056	986,152	1,026,891
2	P&GA	927,164	922,138	947,755
3	HR	346,207	601,986	623,758
4	Training and Development	2,349,706	2,628,921	2,728,608
5	PMO	364,756	386,537	389,265
6	Other Services	9,989,378	10,273,021	10,460,969
7	**Total EWSI**	14,947,267	15,798,756	16,177,246
	ENGLP			
8	SCM	16,140	10,792	11,094
9	P&GA	15,434	16,684	17,151
10	HR	6,352	48,456	49,813
11	Training and Development	43,493	3,749	3,854
12	PMO	-	-	-
13	Other Services	236,190	-	-
14	**Total ENGLP**	**317,608**	**79,681**	**81,912**
15	**% Allocation to ENGLP**	**2.1%**	**0.5%**	**0.5%**

Table 4-STAFF-53-2
ECSI Shared Services Costs Allocated to ENGLP Aylmer 2018-2020
($)

	Shared Service	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	ECSI			
1	Management Oversight	345,000	315,000	323,820
2	Finance	-	240,000	246,720
3	**Total ECSI**	**345,000**	**555,000**	**570,540**
	ENGLP			
4	Management Oversight	83,500	50,000	51,400
5	Finance	-	50,808	52,231
6	**Total ENGLP**	**83,500**	**100,808**	**103,631**
7	**% Allocated to ENGLP**	**24.2%**	**18.2%**	**18.2%**

Table 4-STAFF-53-3
EOUI Shared Services Costs Allocated to ENGLP Aylmer 2018-2020
($)

	Shared Service	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EOUI			
1	Management Oversight	206,000	200,000	205,600
2	Finance	-	150,000	154,200
3	Regulatory	85,000	300,000	308,400
4	HSE	15,000	150,000	154,200
5	Board of Directors	9,333	12,000	12,336
6	Office Facilities	30,000	175,000	179,461
7	**Total**	**345,333**	**987,000**	**1,014,197**
	ENGLP			
8	Management Oversight	28,001	56,453	58,034
9	Finance[1]	-	42,340	43,526
10	Regulatory	30,404	84,680	87,051
11	HSE	-	46,552	47,855
12	Board of Directors	9,333	6,000	6,168
13	Office Facilities	8,761	24,638	25,328
14	**Total ENGLP**	**76,500**	**260,664**	**267,962**
15	**% Allocated to ENGLP**	**22.2%**	**28.0%**	**28.0%**

[1] As described in response to 4-STAFF-54, EPCOR Electricity Distribution Ontario (EEDO) will be providing this service to ENGLP Aylmer instead of EOUI at the same cost.

Table 4-STAFF-53-4
Corporate Shared Services Costs Allocated to ENGLP Aylmer 2018-2020
($)

	Expense Category	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EUI			
1	Corporate Costs Directly Assigned	19,968,193	20,390,794	20,926,088
2	Corporate Costs Allocated	55,850,291	55,072,991	56,521,838
3	Corporate Asset Usage Fees	16,062,397	16,848,957	20,364,502
4	**Total EUI Costs**	**91,880,881**	**92,312,742**	**97,812,428**
	ENGLP			
5	Corporate Costs Directly Assigned	80,014	88,936	91,080
6	Corporate Costs Allocated	252,513	256,184	265,112
7	Corporate Asset Usage Fees	73,457	82,452	83,025
8	**Total ENGLP Costs**	**405,984**	**427,572**	**439,217**
9	**% Allocation to ENGLP**	**0.4%**	**0.5%**	**0.4%**

Table 4-STAFF-53-5
Directly Assigned Corporate Services Costs to ENGLP 2018-2020
($)

	Expense Category	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EUI			
1	IS Application Support	8,118,705	8,430,288	8,753,313
2	IS desktops, printers and network support	7,609,141	8,130,508	8,284,086
3	Supply Chain Management - Space Rent	3,617,068	3,616,075	3,668,601
4	Supply Chain Management - Security	67,857	68,201	69,830
5	Health & Safety	555,422	145,722	150,258
6	**Total EUI Costs**	**19,968,193**	**20,390,794**	**20,926,088**
	ENGLP			
7	IS Application Support	37,016	42,915	44,508
8	IS desktops, printers and network support	40,133	46,021	46,572
9	Supply Chain Management - Space Rent		-	-
10	Supply Chain Management - Security		-	-
11	Health & Safety	2,865	-	-
12	**Total ENGLP Costs**	**80,014**	**88,936**	**91,080**
13	**% Allocation to ENGLP**	**0.4%**	**0.4%**	**0.4%**

Table 4-STAFF-53-6

EUI Corporate Shared Services Costs Allocated to ENGLP 2018-2020

($)

	Function	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EUI			
1	Supply Chain Management	7,462,510	7,577,374	7,722,178
2	Human Resources	7,428,128	7,199,148	8,170,483
3	Information Systems	12,282,369	11,816,616	11,796,177
4	Corporate Finance Services	4,755,008	4,861,651	4,980,423
5	Executive and Executive Assistants	2,953,580	3,058,705	3,150,533
6	Treasury	1,864,473	2,233,162	1,948,864
7	Board	1,671,489	1,512,883	1,519,621
8	Audit and Risk Management	2,096,949	1,905,659	1,948,520
9	Public and Government Affairs	5,932,171	6,043,687	6,351,807
10	Legal Services	2,587,116	2,587,832	2,687,550
11	Health Safety & Environment	862,509	766,174	791,876
12	Incentive Compensation	5,953,989	5,510,100	5,453,806
13	**EUI Total**	**55,850,291**	**55,072,991**	**56,521,838**
	ENGLP			
14	Supply Chain Management	28,930	28,633	29,240
15	Human Resources	36,997	36,454	41,283
16	Information Systems	56,866	57,129	56,939
17	Corporate Finance Services	19,384	19,267	19,780
18	Executive and Executive Assistants	11,245	11,167	11,502
19	Treasury	3,857	4,199	3,788
20	Board	7,169	6,193	6,221
21	Audit and Risk Management	6,713	5,790	5,911
22	Public and Government Affairs	39,890	47,947	50,619
23	Legal Services	9,850	9,448	9,812
24	Health Safety & Environment	4,212	3,795	3,922
25	Incentive Compensation	27,400	26,162	26,095
26	**ENGLP Total**	**252,513**	**256,184**	**265,112**
27	**% Allocation to ENGLP**	**0.5%**	**0.5%**	**0.5%**

Table 4-STAFF-53-7
Corporate Asset Usage Fees to ENGLP 2018-2020
($)

	Function	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
	EUI			
1	Leasehold Assets	1,559,244	1,534,533	1,500,762
2	HRIS	410,046	452,068	530,428
3	IS Infrastructure	10,692,944	11,436,326	15,391,681
4	Financial Systems	2,443,965	2,546,866	2,419,400
5	Furniture and Fixtures	950,774	879,164	517,685
6	Vehicles	5,424	-	4,546
7	**Total EUI**	**16,062,397**	**16,848,957**	**20,364,502**
	ENGLP			
8	Leasehold Assets	4,291	4,478	4,472
9	HRIS	1,865	2,100	2,492
10	IS Infrastructure	55,639	63,939	65,514
11	Financial Systems	8,762	9,078	8,644
12	Furniture and Fixtures	2,875	2,857	1,882
13	Vehicles	25	-	21
14	**Total ENGLP**	**73,457**	**82,452**	**83,025**
15	**ENGLP %**	0.5%	0.5%	0.4%

4-STAFF-54

Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 37-39**

Request:

Table 4.3.3.3-5 provides the ECSI Shared Services costs allocated to EPCOR Aylmer and Table 4.3.3.3-7 provides the EOUI Shared Services Costs allocated to EPCOR Aylmer.

Both tables include Management Oversight and Finance. Please explain the type of services provided under this category by each of the affiliates, identify any duplication of services and justify why EPCOR Aylmer needs the services from both affiliates.

Response:

Management Oversight:

ECSI management oversight reflects the supervisory and general oversight of the Senior Vice President, Commercial Services to the Vice President, Ontario Region. The Vice President, Ontario Region reports directly to the Senior Vice President, Commercial Services. EOUI management oversight reflects the supervisory and direct management of the Vice President, Ontario Region to the General Manager of ENGLP Aylmer as well as general oversight to the employees of ENGLP Aylmer. The General Manager of ENGLP Aylmer reports directly to the Vice President, Ontario Region.

ENGLP does not consider this arrangement a duplication of services as each level of management oversight is in place to ensure its direct reports are meeting performance expectations and to provide direct supervision at the appropriate level (i.e. direction, feedback, assistance, performance management). By providing management oversight using existing resources from other entities, the utility is making the most efficient use of available resources and avoiding having to employ all these levels of oversight in the utility. In this case, the President and CEO of EUI provides management oversight to the Senior Vice President, Commercial Services who provides oversight to the Vice President, Ontario Region and the Vice President, Ontario Region provides oversight to the General Manager of ENGLP Aylmer.

Finance:

At the time of the Application, it was thought that ENGLP Aylmer would be receiving Finance services from EOUI; however, this has subsequently changed. The Finance services originally expected to come from EOUI will now be provided by EPCOR Electricity Distribution Ontario (EEDO) as the employee providing the service will now remain an employee of EEDO as opposed to moving to EOUI. This change will have no impact to the Revenue Requirement.

Therefore, ENGLP Aylmer will receive Finance shared services from ECSI and EEDO.

ECSI Finance services reflects full cycle accounting and financial reporting support related to ENGLP's Aylmer operations (including day-to-day accounting transactions, capital asset accounting, support for regulatory filings, preparation of annual budgets and periodic financial forecasts, preparing ENGLP financial statements, preparing financial analysis related to ENGLP Aylmer operations and developing internal controls). EEDO Finance services reflects supervision of the support provided by ECSI Finance as well as some direct accounting and financial reporting support to ENGLP's Aylmer operations.

ENGLP does not consider these arrangements a duplication of Finance shared services as each affiliate is providing a different service, with ECSI Finance providing the majority of the services and EEDO Finance providing supervision and oversight of the ECSI services, along with some direct accounting and financial reporting support, particularly in the context of OEB regulatory accounting.

4-STAFF-55
Reference: Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 41-42

Request:

EUI's cost allocation process is designed to ensure that the allocation of Corporate Shared Services costs among business units is appropriate, fair and reasonable, cost-effective, predictable, reflects the benefits received by function or cost causation and provides for consistency with the transfer pricing principles in the Affiliate Relationship Code (ARC), EPCOR's ARC Compliance Plan and EUI's Inter-Affiliate Code of Conduct. For the 2020 Test Year, a total of $892,722 has been allocated to EPCOR Aylmer for Shared Services and Corporate Costs. Shared Services constitute 27% of the total OM&A Costs of EPCOR Aylmer for the 2020 Test Year.

Please explain how a cost allocation of $892,722 for a small utility is fair and reasonable, and cost-effective.

Response:

The Corporate Shared Services provided to ENGLP Aylmer are required to support the operations to ensure safe and reliable delivery of gas. Regardless of the utility size, the utility is still required to comply with all regulatory requirements and ensure the development, implementation and maintenance of programs in support of the operations and regulatory requirements including for example:

- Monitoring and addressing cyber security concerns,
- Ensuring stabile, reliable and secure IT systems and data storage,
- Complying with financial and regulatory reporting,
- Ensuring ongoing customer engagement and outreach,
- Maintenance of all operational documentation,
- Monitoring and ensuring ongoing compliance with health, safety and environmental regulations,

- Developing and maintaining competitive employee compensation and benefits packages,
- Monitoring compliance and conformance training for staff and ensuring the provision of required training.

EUI utilizes a centralized approach to ensure the provision of services in support of the above areas, as well as the other essential shared service areas described within paragraphs 84 through 130 of Exhibit 4, Tab 1, Schedule 1. The approach is fair and reasonable as all EUI subsidiaries are treated the same (i.e., consistent cost allocation) and pays its fair share of costs and no EUI subsidiary is cross subsidizing another EUI subsidiary.

Further, this approach also provides economies of scale as the costs for this service are shared amongst all of EUI subsidiaries, including ENGLP Aylmer and provides ENGLP Aylmer with access to a wealth of knowledge and expertise, as well as the underlying systems and assets required to provide that service that would not normally be resident within a smaller utility. Through the shared service approach, ENGLP Aylmer obtains the staff resources and underlying systems necessary for the provision of utility services at a lower cost than were the utility to self-supply these services, or attempt to operate in their absence. An indication of the efficiency of the shared service model is that ENGLP's proposed OM&A costs per customer in 2020 are lower than the OEB approved costs in 2011.[1]

[1] Exhibit 1, Tab 1, Schedule 1, p. 37, para 83.

4-STAFF-56
Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 46-47**

Request:

EPCOR has provided a general description of the corporate services that are provided. One of the items include Board Costs which represents corporate governance functions to EPCOR and its subsidiaries.

Please describe the corporate governance services that would be required by EPCOR Aylmer.

Response:

The EPCOR Utilities Inc. ("EUI") Board of Directors ("EUI Board") provides governance functions that set the overall objectives, strategic direction, and policies for the EPCOR group of companies, including ENGLP. The functions of the EUI Board include:

- Establishing the strategic objectives and direction of EPCOR group of companies.
- Reviewing and approving corporate-wide policies.
- Providing direction and oversight to safeguard and maintain the long-term value of corporate assets.
- Reviewing and approving significant financial matters for the EPCOR group, including the provision of significant internal financing to subsidiaries.
- Approving EUI consolidated capital and operating budgets, to meet the objectives established in the EUI group's strategic plan.
- Appointing the auditors of and approving EUI's annual consolidated financial statements.
- Approving corporate-wide compensation policies and programs.
- Evaluating and assessing corporate-wide performance against strategic, operating and capital plans.
- Understanding and monitoring corporate-wide business risks.

These functions are very customary in the context of a group of companies and complement the responsibilities of a subsidiary board, such as the EOUI Board of Directors (“EOUI Board”). For example, while the EUI Board carries out the above noted functions, the EOUI Board:

- has the authority and responsibility to manage the business and affairs of ENGLP through oversight of EOUI management;
- appoints the auditors of and approves ENGLP’s annual financial statements;
- approves the operating and capital budgets of ENGLP;
- makes final decisions on the approval of acquisitions by ENGLP;
- approves all issuances, re-financing or prepayments of internal long term borrowing of ENGLP;
- monitors ENGLP’s compliance with legal requirements and significant policies;
- approves all distributions by ENGLP to its partners and all equity issuances/transactions; and,
- appoints the management of EOUI.

4-STAFF-57
Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pgs. 53-54**

Request:

EPCOR is seeking recovery of regulatory costs related to the 2018 IRM Application (EB-2018-0235) which included proposed IRM adjustments for 2016, 2017 and 2018, disposition of certain deferral and variance account balances and other matters. The total regulatory costs for the application was $216,481 which is included in the total regulatory costs ($925,014) requested for 2020 rates (amortized over a five-year period).

(a) Please explain why EPCOR is seeking recovery of regulatory costs for a historic year and which is not related to the current cost of service and IRM application?

(b) Is EPCOR of the opinion that OM&A type costs incurred during an IRM regime should be recoverable in future periods?

Response:

(a) ENGLP views the costs associated with the 2018 IRM application (EB-2018-0235) as being non-routine and acknowledges that this request for recovery is a special circumstance (see response to (b) below). These costs are incremental to what was included when NRG's rates were last set through a cost of service process (EB-2010-0018), and exceeds the utility's materiality threshold of $50,000. The 2018 IRM Application (EB-2018-0235) was not a typical IRM adjustment. It was filed as a stop-gap measure, in lieu of a previously filed cost-of-service application (put in abeyance due to a change in the utility's ownership). As a result, it contained a number of issues beyond a mechanistic price cap adjustment which were scheduled to (or would normally) be dealt within the cost-of-service application, including: (a) moving one rate class (Rate 6) to a fully fixed rate; (b) changing the utility's rate year; (c) resolution of rates for historic years (based on interim rates that had been in place for an extended period of time); (d) the withdrawal of the cost-of-service application that was in abeyance; (e) fixed charge increases for all rate classes; and (f) clearance of significant DVA balances. The

EB-2018-0235 proceeding was resolved via a full settlement proposal, which as the Board noted: "The OEB staff submission indicated that approval of the settlement proposal would dispose of all the issues raised in NRG's cost of service proceeding. If EPCOR agrees with the views of OEB staff, EPCOR should file a letter with the OEB withdrawing the original NRG application so that the proceeding can be closed." ENGLP's view is that the EB-2018-0235 application was not merely an IRM application, but a hybrid application that bridged the EB-2010-0018 rate regime with this application.

(b) ENGLP is not of the opinion that routine OM&A costs incurred during an IRM regime should be recoverable in future periods.

4-STAFF-58

Reference: **Exhibit 4/ Tab 1/ Schedule 1/Pgs. 57-65**
Exhibit 1/ Tab 1/ Schedule 1/Pgs. 40-41

Request:

EPCOR is proposing to adopt Enbridge Gas' approved depreciation rates from EB-2011-0210 as it believes that these rates are more reflective of the useful lives of assets except for Meters and Vehicles – Transportation Equipment.

(a) Please explain the analysis EPCOR performed to conclude that the proposed useful lives are more reflective of actual useful lives of the assets.

(b) Some of the asset classes have been broken down into further categories (i.e. buildings, automotive, meters, regulators). Please explain the process EPCOR used to identify these categories and how the asset balance pertaining to each category was allocated.

(c) Please confirm that depreciation is calculated on a straight line basis starting in 2020 for all asset classes. If not, please identify the asset classes that are not depreciated on a straight line basis and the method of depreciation used.

(d) The depreciation rate for computer software is proposed to change from 20% to 10% to ensure consistency with EPCOR Inc.'s depreciation policy. Please explain whether this is reflective of EPCOR's asset class' actual useful life for the Aylmer operations.

Response:

(a) NRG's depreciation policies and information supporting its determination of the depreciation rates previously used for the Aylmer operations were not available to ENGLP. The rates used by NRG do align with rates used by other utilities for similar assets and there is no operational evidence that the existing rates were reflective of the true useful life of the assets or to indicate that the shorter (in most cases) useful lives used by NRG would be appropriate for the Aylmer operation.

With a small utility such as ENGLP Aylmer, it is uneconomical to do a depreciation study for these specific assets. Given the close proximity of the Enbridge Gas assets to the Aylmer assets, support relied on by Enbridge Gas in the determination of its approved rates from EB-2011-0210 were believed to be a close proxy for a depreciation study of the Aylmer specific assets. In addition, the Enbridge Gas depreciation rates aligned more closely with the useful lives as determined for similar utility assets in other EPCOR businesses, providing further assurance that Enbridge Gas' rates were reasonable for the Aylmer assets.

(b) ENGLP used NRG's historical asset categories. The continued use of these categories was to ensure comparability between historic and forward-looking data. Additionally, the categories are aligned with USoA categories. Asset balance pertaining to each category will not be allocated, they will be based on the specific asset additions related to capital projects having these asset categories.

(c) Confirmed. ENGLP's depreciation is calculated on a straight line basis for all asset classes starting 2020.

(d) ENGLP considers that a 10-year useful life more closely reflects the economic useful life of the software used for Aylmer operations. A significant portion of the software asset class relates to utility billing software which was acquired in 2016 and ENGLP expects to be used beyond 2021.

4-STAFF-59

Reference: **Exhibit 4/ Tab 1/ Schedule 1/Pgs. 62, 66-68**
Exhibit 4/ Tab 2/ Schedule 1/Pg. 10 – Tax Return

Request:

Regarding taxes,

(a) It states that EPCOR's effective tax rate is 26.5% based on the provincial and federal tax rate. EPCOR's taxes payable is calculated by including a share of its taxable income in each partner's tax return. Please indicate the effective tax rate for each of EPCOR's partners.

(b) On page 10 of EPCOR's 2017 tax return, line 206 adds capital items expensed of $1M back to income.

(i) Please explain what this adjustment is for.
(ii) Please explain whether a similar adjustment is required in the calculation of regulatory income taxes in Table 4.5.2-1 on page 67, and why.

(c) On page 62, EPCOR has proposed to dispose meters and has forecasted a $162,000 loss on meters in 2020. Please explain how this has been treated for CCA purposes on page 68 in Table 4.5.2-2. Please revise the evidence as necessary.

(d) In the calculation of taxes payable on page 67, please explain how the interest expense is derived. Please explain why deemed interest expense is not used. Please revise the evidence as necessary.

Response:

(a) Each of EPCOR's partners would have an effective tax rate of 26.5% (combined 15% federal rate and 11.5% Ontario M&P rate) on its respective share of EPCOR's taxable income for a given fiscal period.

(b) (i) $999,999 of this adjustment relates to a success fee paid by ENGLP to an affiliate for services performed in relation to the acquisition. ENGLP did not have its own internal resources available to perform the diligence required related to the acquisition. The amount was added back as an expense but included in CCA Class 14.1.

(ii) The amount relates to the 2017 fiscal year which is not part of the regulatory income taxes calculations in Table 4.5.2-1.

(c) The disposal will not impact the calculation of CCA in Table 4.5.2-2 of Exhibit 4, Tab 1, Schedule 1. The disposition of the meters noted in paragraph 143 of Exhibit 4, Tab 1, Schedule 1 assumes the meters are disposed at NBV with no proceeds. The CCA schedule in Table 4.5.2-2 is only impacted (reduced) by the greater of cost of the assets disposed of and the proceeds received on disposition. As the meters will be written off, there will be no impact to the CCA calculations in Table 4.5.2-2.

(d) ENGLP has recalculated interest expense for its calculation of taxes payable in the same manner as the interest expense for the purposes of determining the revenue requirement. This is calculated as the sum the interest expense of the ST debt and LT debt. The interest expense of the ST debt is the product of 4% of 2020 mid-year rate base and OEB's deemed ST debt interest rate of 2.82%. The interest expense of the LT debt is the product of 56% of 2020 mid-year rate base and the weighted cost of LT debt using debt rates of the utility's actual and forecasted portfolio of LT debts for the test year, weighted by the principal of each LT debt as outlined in the Board's Filing Requirements for Natural Gas Rate Applications.[1] This calculation does not result in deemed interest expense as ENGLP's actual debt portfolio includes affiliate debt that is at a rate lower than the deemed debt rate.

More specifically, the weighted cost of LT debt is calculated as the sum of the interest expenses of ENGLP's actual and forecasted debt portfolios. ENGLP's actual debt portfolio consists of $8.66 million of LT debt with a fixed interest rate of 3.83%. ENGLP's forecasted debt portfolio consists of $1 million of LT debt to be borrowed in

[1] Ontario Energy Board, Filing Requirements for Natural Gas Rate Applications, Chapter 2: Cost of Service Applications, dated February 16, 2017, p. 32.

2020 at OEB's deemed LT debt interest rate of 4.13%. The borrowing of $1 million of LT debt in 2020 aims to align ENGLP's mid-year LT debt balance to 56% of its mid-year Rate Base.

See ENGLP's response to 9-STAFF-78 for the updated revenue requirement, bill impacts and rates reflecting the recalculation of interest expense for its calculation of taxes payable, as described above.

4-STAFF-60
Reference: **Exhibit 4 / Tab 1 / Schedule 1/ Pg. 64**

Request:

EPCOR has proposed to update the depreciation rate for the IGPC pipeline from 5.00% to 1.98%. In order to protect EPCOR and its ratepayers, EPCOR has proposed the extension of the requirement for an Irrevocable Letter of Credit from IGPC for the net book value of the assets in rate base.

(a) Please indicate whether the Letter of Credit will reflect the net book value of the IGPC assets in rate base as of January 1, 2020.

(b) Has EPCOR requested the Irrevocable Letter of Credit from IGPC and is IGPC prepared to provide the Letter of Credit?

Response:

(a) At a minimum, the Letter of Credit will reflect the net book value of the IGPC assets in rate base as of January 1, 2020 related to the Pipeline Cost Recovery Agreement as addressed in EB-2006-2043. That net book value is expected to be approximately $2.106 million at the end of 2019. ENGLP understands that EB-2006-2043 does not address requirements for a Letter of Credit related to any capital additions to the IGPC assets that might take place subsequent to the initial installation. As a result ENGLP and IGPC are in discussions as to whether ENGLP is able to extend credit regarding these additions. The majority of these capital additions are taking place in 2018 and 2019. The net book value of these new capital additions is expected to be approximately $1.573 million at the end of 2019.

(b) ENGLP has requested an Irrevocable Letter of Credit from IGPC as it relates to the IGPC asset base covered in EB-2006-2043 and IGPC has indicated they are prepared to provide the Letter of Credit. As detailed in (a) above, ENGLP and IGPC are in discussions related to extension of credit related to recent capital additions to their assets.

4-STAFF-61
Reference: **Exhibit / Tab 1/ Schedule 1/Pg. 66**

Request:

Forecast property tax is based on the assessed market value of the pipeline assets in the previous year, adjusted for the addition of pipelines in the forecast year. Please provide a comparison of the property taxes and the assessed market value of the pipelines in the previous year as well as the pipeline additions in each year from 2017 to 2020.

Response:

A summary of the 2017 and 2018 property taxes and assessed market values are provided in the tables below:

Table 4-STAFF-61-1
2017 Property Taxes and Assessed Market Value

		A	B	C	D
	Municipality	**Tax Roll Account**	**Tax Class per assessments**	**2017 assessed value ($)**	**2017 tax levy ($)**
1	Norfolk (IGPC)	2854 050 404 27500 0000	PTN – Pipeline	2,374,500	70,292
2	SW Oxford	3211 010 090 02000 0000	PTN – Distribution Pipeline	901,000	20,189
3	Bayham	3401 000 009 00800 0000	Pipeline	2,674,500	67,823
4	Bayham	3401 002 002 00400 0000	Pipeline	280,500	6,934
5	Bayham	3401 004 002 00200 0000	Pipeline	309,500	7,651
6	Malahide	3408 000 070 00600 0000	PT – Pipelines	5,544,000	144,045
7	Malahide	3408 012 002 00300 0000	PT – Pipelines	263,000	6,833
8	Malahide	3408 014 030 00600 0000	PT – Pipelines	3,328,750	83,890
9	Aylmer	3411 040 000 00500 0000	PTN – Distribution Pipeline	1,433,250	38,737
10	Eigin	3418 000 011 00903 0000	PTN – Municipal Pipeline	175,500	4,688
11	Eigin	3418 016 002 00101 0000	PTN – Municipal Pipeline	425,250	11,359
12	Thames Centre	3926 000 060 23400 0000	PT – Pipelines	2,625,500	56,314
13	London	3936 080 070 21800 000A4	Distribution Pipeline	12,375	422
14			**Total**	**20,347,625**	**519,177**

Table 4-STAFF-61-2
2018 Property Taxes and Assessed Market Value

	Municipality	A Tax Roll Account	B Tax Class per assessments	C 2018 assessed value ($)	D 2018 tax levy ($)
1	Norfolk (IGPC)	2854 050 404 27500 0000	PTN – Pipeline	2,521,000	75,947
2	SW Oxford	3211 010 090 02000 0000	PTN – Distribution Pipeline	1,081,641	24,433
3	Bayham	3401 000 009 00800 0000	Pipeline	2,808,500	78,340
4	Bayham	3401 002 002 00400 0000	Pipeline	289,870	7,106
5	Bayham	3401 004 002 00200 0000	Pipeline	316,000	7,746
6	Malahide	3408 000 070 00600 0000	PT – Pipelines	5,754,500	150,932
7	Malahide	3408 012 002 00300 0000	PT – Pipelines	269,928	6,901
8	Malahide	3408 014 030 00600 0000	PT – Pipelines	3,314,500	84,744
9	Aylmer	3411 040 000 00500 0000	PTN – Distribution Pipeline	1,486,500	41,214
10	Eigin	3418 000 011 00903 0000	PTN – Municipal Pipeline	178,973	4,763
11	Eigin	3418 016 002 00101 0000	PTN – Municipal Pipeline	461,437	12,521
12	Thames Centre	3926 000 060 23400 0000	PT – Pipelines	2,715,541	57,383
13	London	3936 080 070 21800 000A4	Distribution Pipeline	12,750	424
14			**Totals**	**21,211,140**	**552,454**

ENGLP notes that the 2017 and 2018 tax levies in the tables above include a small amount of supplemental charges from supplemental assessments from 2016 through 2018.

The 2017-2020 pipeline additions consist of one planned pipeline to be constructed in 2019. The details of this pipeline are in the table below:

Table 4-STAFF-61-3
2017-2020 Pipeline Additions

	Municipality	A Pipeline Type	B Estimated Length (m)	C Estimated Length (ft)	D Estimated Diameter	E Estimated Value ($)*
1	SW Oxford	Plastic	8,800	28,871	2	269,370

* The estimated value calculation for property tax purposes is derived from the length in feet multiplied by the applicable rate (9.33 for plastic distribution pipelines as per Table 2 of Ontario Regulation 282/98.

5-STAFF-62
Reference: **Exhibit 5 / Tab 1 / Schedule 1**

Request:

Please provide the achieved return on equity for 2018.

Response:

The achieved Return on Equity (ROE) for 2018 is 4.48%. The calculations are below:

Table 5-STAFF-62-1
2018 Achieved ROE

	Item	A Calculation	B Value
1	Regulatory Net Income Before Adjustments		259,605
2	Add: Actual Interest Expense		363,010
3	Less: Deemed Interest Expense		(320,896)
4	Adjustment to Taxable Income	R2 + R3	42,114
5	Adjustment to Tax Expense for Regulated ROE Purposes	R4 x 26.5%	(11,160)
6	Future Tax		0
7	Current Tax		0
8	Adjusted Net Income for ROE Purposes	R1 + R4 + R6 + R7	248,445
9	Dec 31, 2017 Net PP&E and Intangibles		13,410,000
10	Dec 31, 2018 Net PP&E and Intangibles		14,339,555
11	2018 Average PP&E and Intangibles	(R9 + R10) / 2	13,874,778
12	Equity Weighting		40%
13	Deemed Equity	R11 x R12	5,549,911
14	2018 Achieved ROE	R8 / R13	4.48%

5-STAFF-63

Reference: **Exhibit 5 / Tab 1 / Schedule 1/ Pgs. 3-4**

Request:

In November 2017, EPCOR borrowed $8.66 million from its parents company, EPCOR Utilities Inc. The derivation of the interest rate includes a credit spread of 1.55% from the Government of Canada 30-year rate and is based on market rates observed in November 2017.

(a) How does the credit spread of 1.55% compare to Enbridge Inc., the parent of Enbridge Gas Inc.?

(b) EPCOR expects to add $0.998 million of new long-term debt in 2020. At what rate will this debt be secured?

Response:

(a) At the time the intercompany loan was made, the 1.55% spread compared favourably to the spread of Enbridge Inc. which was 2.35%.

(b) The rate for the note payable has not yet been established. EPCOR Utilities Inc.'s ("EUI") practice is that the terms of the note payable, including the rate, will be comparable to lending agreements with financial institutions at the time the loan is required.

7-STAFF-64

Reference: **Exhibit 7 / Tab 1 / Schedule 1/ Pg. 2**

Request:

In table 7.1-1, EPCOR has provided the current approved revenue to cost (RtC) ratios and the proposed RtC ratios. In many cases the proposed RtC ratios are closer to 1.00. However, in case of Rate 1 Industrial customers, the RtC ratio has been moved to 1.35 from 0.72 and in case of Rate 4 customers, the RtC ratio has been moved to 0.84 from 1.14.

(a) Please explain why the RTC ratio has not been moved closer to 1.00 for the two types of customers referred to above.

(b) Please revise the RTC ratio for the above two customer types closer to 1.0 and present the results (including bill impacts).

Response:

(a) The Rate 1 rate class includes three sub-classes of customers which share the same fixed and variable rates: Rate 1 Residential, Rate 1 Commercial and Rate 1 Industrial. ENGLP's objective was to propose a rate that would result in a RtC ratio of close to 1.0 for the entirety of the Rate 1. Any adjustment made to the Rate 1 rates in an effort to move the revenue to cost ratio (RtC) for Rate 1 Industrial closer to 1.00 (i.e. lower the over rate), would have resulted in reduced RtC ratios for both Rate 1 Residential and Rate 1 Commercial which are currently at 0.98 and 1.06 respectively. As a result, the overall RtC ratio for Rate 1 would drop from the proposed ratio of 1.0.

Further, such a change to the RtC ratio for Rate 1 Industrial will also have a direct impact for Rates 2 through 6 given that a decrease in proposed revenue for all Rate 1 customer sub-classes (Residential, Commercial and Industrial) will need to be offset by an increase in the proposed revenue from customers in Rates 2 through 6.

For Rate 4 customers, ENGLP is proposing an increase of 7.42%. This increase results in a RtC ratio of 0.86 which in within a range of 20% of 1.0. ENGLP notes that other than Rate 5 and Rate 4, all other customers will experience no increase or a decrease in rates.

In the process of setting the proposed rates, ENGLP considered the RtC ratios and customer rate impacts for each customer class and determined that the proposed rates strike a reasonable balance for all customer classes.

(b) As noted in the response to (a) above, modifying the RtC ratio for one rate class will have implications for other rate classes. For the purpose of responding to this request, ENGLP has provided a scenario which includes the following four steps to account for the interdependency among rate classes:

i. Revise the RtC ratio for Rate 1 Industrial from 1.38 to 1.20. Note that this adjustment will in turn reduce the RtC ratio for Rate 1 Residential and Rate 1 Commercial given they are also sub-classes of Rate 1.

ii. Calculate the resulting RtC ratios for R1 Residential and R1 Commercial, and the subsequent increase in revenues to be recovered from Rate 2 through Rate 6.

iii. Determine the resulting RtC ratios for Rate 2 through 6 (assuming the resulting revenue deficiency is recovered in proportion to revenues for each of these rate classes).

The revised RtC ratios are provided in the table below. The RtC ratio for Rate 1 (including all three sub-classes) decreases from 1.0 to 0.87, with the offsetting RtC ratio increases for Rate 2 through Rate 6 ranging from a minimum of 0.29 for Rate 5 (from 0.58 to 0.87) and a maximum of 0.54 for Rate 6 (from 1.09 to 1.63).

Table 7-STAFF-64-1
Distribution Revenue to Cost Comparison Excluding Commodity
($ thousands)

	A **Total**	B **Rate 1**	C **Rate 1 - Residential**	D **Rate 1 - Commercial**	E **Rate 1 - Industrial**	F **Rate 2**	G **Rate 3**	H **Rate 4**	I **Rate 5**	J **Rate 6**
1 Proposed Revenue	6,741	4,641	3,784	652	204	239	255	221	98	1,287
2 Cost	6,741	5,320	4,442	708	170	161	184	172	113	791
3 Over (Under) Contribution	0	(679)	(658)	(55)	34	78	72	49	(15)	496
4 Scenario – Rate 1 Industrial RtC Ratio at 1.20	1.00	0.87	0.85	0.92	1.20	1.48	1.39	1.28	0.87	1.63
5 Revenue to Cost Ratio	1.00	1.00	0.98	1.06	1.38	0.99	0.93	0.86	0.58	1.09

The resulting updated bill impacts are provided in the Table 7-STAFF-64-2, below.

Table 7-STAFF-64-2
Summary of Annual Distribution Rate Impacts of a Typical Customer
($)

	Rate Class	A **Annual Bill Current Rates**	B **Annual Bill at Scenario Rates**	C **Change (B-A)**	D **Change (%)**
1	Rate 1 - Residential	469.92	408.43	(0.06)	-13.08%
2	Rate 1 - Commercial	832.18	703.11	(0.13)	-15.51%
3	Rate 1 - Industrial	2,080.55	1,736.04	(0.34)	-16.56%
4	Rate 2	2,691.46	4,018.47	1.33	49.30%
5	Rate 3	93,609.24	139,765.51	46.16	49.31%
6	Rate 4	2,283.44	3,662.16	1.38	60.38%
7	Rate 5	14,922.42	24,415.68	9.49	63.62%
8	Rate 6	1,133,887.44	1,286,601.99	152.71	13.47%

7-STAFF-65
Reference: **Exhibit 7 / Tab 1 / Schedule 1/ Pg. 6**

Request:

Regulatory costs are functionalized to Administration and General expense.

Please indicate the portion of regulatory costs that are allocated to IGPC for the 2020 Test Year.

Response:

The proportion of the regulatory expense allocated to IGPC for the 2020 Test Year is 12.9% or $27,391.

7-STAFF-66

Reference: **Exhibit 7 / Tab 1 / Schedule 1/ Pg. 9**

Request:

The classification for Distribution Mains remains unchanged from the previous cost allocation study (by NRG) at 66.53% delivery demand and 33.47% unweighted customer. All the other classification factors have been updated.

(a) Please explain why the classification for Distribution Mains has remained unchanged.

(b) Please explain what "unweighted customer" means.

Response:

(a) The basis used to classify Distribution Mains to Delivery Demand and Unweighted Customer classifications is a zero-intercept study completed by NRG. ENGLP investigated completing an update to this zero-intercept study, but the historical accounting records could not provide the level of detail required to complete the study. Also, the 66.53% delivery demand and 33.47% unweighted customer are in a close range with factors used by other utilities.[1] As such, ENGLP has proposed to use the existing classification factors previously approved by the Board for NRG.

(b) "Unweighted customer" means the actual number of customers in each customer rate class.

[1] Examples include (1) Gazifere Proposed Fully Allocated Cost Study 2018 which classifies distribution mains as 73% demand and 27% customer related (http://publicsde.regie-energie.qc.ca/projets/406/DocPrj/R-4003-2017-B-0274-DemAmend-Piece-2017_10_31.pdf), and (2) Enbridge Fully Allocated Cost Study EB-2012-0459, Exhibit G2, Tab 1, Schedule 1 which classifies distribution mains as 66% demand and 34% customer related.

7-STAFF-67

Reference: **Exhibit 7 / Tab 1 / Schedule 1/ Pg. 9**

Request:

EPCOR has provided a comparison of the allocated customer-related costs per customer per month by rate class to the level of the proposed fixed monthly customer charges. The proposed fixed monthly charges are below the customer cost for Rate 1 through 5.

What portion of the customer related costs will EPCOR recover from the fixed monthly charge if the OEB were to accept the requested change for 2020 rates?

Response:

On a combined basis for Rate 1 through 5, the proposed fixed monthly charges for 2020 will recover 46.7% of the allocated customer-related costs.

8-STAFF-68

Reference: **Exhibit 8 / Tab 1 / Schedule 1/ Pg. 2**

Request:

EPCOR has proposed an increase to the fixed monthly charge for customers in Rate 1, Rate 2, Rate 3 and Rate 5.

(a) Please explain why EPCOR has not proposed an increase to the fixed monthly charge for Rate 4 customers?

(b) If EPCOR was required to increase the fixed monthly charge for Rate 4 customers, what would it be?

(c) The current fixed monthly charge for Rate 3 and Rate 5 customers is $172.50 (proposed to increase to $190). Why is the fixed monthly charge for Rate 4 customers $17.25 and comparatively lower than the monthly charge for Rate 3 and Rate 5 customers?

Response:

(a) ENGLP has not proposed an increase in the fixed monthly charge for Rate 4 customers due to their seasonal usage profile. Rate 4 customers are generally smaller grain dryer operations that use the majority of their gas (approximately 96%) during the months of October to December. During the months of January to August customers in this rate class use little or no gas. ENGLP was concerned that a material increase in the fixed monthly charge could motivate these customers to disconnect their service during months where their usage was low or zero. This would reduce the efficiency of the utility as ENGLP would be directing resources to disconnect and reconnect these customers.

(b) If ENGLP was required to increase the fixed monthly charge for Rate 4 customer, we would recommend that it not be a material increase due to the above detailed concern regarding the seasonality of their demand. An increase to a maximum of $20 per month (increase of $2.75 per month) would be recommended. This would continue to provide some incentive for this class of customers to remain connected as the disconnect and reconnect fees would total approximately $170 under the rates proposed in this Application.

An increase of the fixed monthly fee to $20 per month, with a proportionate decrease in the variable charge, would result in an increased bill impact for the typical Rate 4 customer. Table 8-STAFF-68-1 provides a comparison of the distribution rate bill impact for a fixed monthly fee of $17.25 versus $20.00 for a typical Rate 4 customer.

Table 8-STAFF-68-1
Bill Impact Comparison for Typical Rate 4 Customer

		A	B	C	D
	Monthly Fixed Charge	**Annual Bill Current Rates**	**Annual Bill Proposed Rates**	**Change ($)**	**Change (%)**
1	$17.25	$2,283.44	$2,452.88	$169.44	7.42%
2	$20.00	$2,283.44	$2,465.77	$182.33	7.98%

(c) The proposed fixed monthly charge for Rate 4 customers of $17.25 is lower than the monthly charge for Rate 3 and Rate 5 customers due to the differing usage profiles and relative size of these different classes of customers.

Rate 3 customers are larger customers who have entered into a minimum one year contract that includes a minimum daily contracted demand for firm and interruptible service of at least 700 m^3 and a qualifying annual volume of at least 113,000 m^3. The typical annual bill for distribution services for these customers is approximately $93,823.04 under proposed rates. The higher fixed monthly charge is intended to allow the utility to recover a higher percent of the fixed monthly cost ($294.36) to service them.

Rate 5 customers are larger customers (typically commercial grain dryers) who have entered into a minimum one year contract that includes a minimum daily contracted demand for firm and interruptible service of at least 700 m^3 and a qualifying annual volume of at least 50,000 m^3. The typical annual bill for distribution services for these customers is approximately $16,652.68 under proposed rates. The higher fixed monthly charge is intended to allow the utility to recover a higher percent of the fixed monthly cost ($353.28) to service them.

8-STAFF-69

Reference: **Exhibit 8 / Tab 1 / Schedule 1/ Pg. 5**

Request:

EPCOR has indicated that it intends to work with IGPC early in 2019 to amend the current Gas Delivery Agreement between EPCOR and IGPC, which has a termination date of September 30, 2020, to reflect the change to the rate structure for Rate Class 6. The rate schedule for Rate 6 will be reviewed in conjunction with the amendment of the Gas Delivery Agreement and any identified changes will be brought forward as part of this proceeding.

(a) Please provide an update on the current negotiations between EPCOR and IGPC to amend the Gas Delivery Agreement.

(b) Would the revisions to the Gas Delivery Agreement have an impact on the distribution rates charged to IGPC for 2020 or the 2020 overall revenue requirement in this application?

(c) Does EPCOR intend to submit the amended Gas Delivery Agreement in this proceeding?

(d) Does EPCOR require OEB approval of the amended Gas Delivery Agreement that is reached between EPCOR and IGPC?

Response:

(a) IGPC and ENGLP agree that the current Gas Delivery Agreement between the parties should be amended to reflect the rate structure for Rate Class 6. Discussions have been initiated between the parties.

(b) No. The revisions to the Gas Delivery Agreement would reflect the fully fixed rate structure and the direct flow through of the customer specific upstream charges implemented as a result of the Board's Decision and Order in EB-2018-0235. These changes are consistent with the proposals in this Application.

(c) ENGLP does not intend to submit the amended Gas Delivery Agreement in this proceeding.

(d) ENGLP does not require OEB approval of the amended Gas Delivery Agreement that is reached between ENGLP and IGPC.

8-STAFF-70

Reference: **Exhibit 8 / Tab 1 / Schedule 1/ Pg. 5**

Request:

EPCOR has proposed to increase the fixed monthly charge from $15.00 to $17.00 to reflect a charge closer to the $21.00 charged by Enbridge Gas Inc. in the surrounding territory. As part of the IRM, EPCOR has also proposed to increase the fixed monthly charge by $1.00 in each year of the IRM period starting 2021 to bring the fixed monthly charge to $21.00 in 2024. EPCOR has indicated that the proposed changes will improve recovery of customer related costs through the fixed charge.

(a) Please reference other Ontario regulated utilities that have received OEB approval to increase the fixed monthly charge in excess of the Price Cap adjustment during the IRM period.

(b) What portion of customer related costs would be recovered through the fixed monthly charge if it is increased to $21 per month?

Response:

(a) ENGLP is unaware of any other Ontario regulated utilities that have received OEB approval to increase the fixed monthly charge in excess of the Price Cap adjustment during the IRM period. However, as detailed in EB-2012-0410, ENGLP understands that Board policy supports the move to a higher percent of the distribution portion of the bill for residential electricity customers to be fixed. The proposal by ENGLP is aligned with this policy and incorporates a rate smoothing element by phasing in the increase over a five year period. In addition, the proposed increase will allow ENGLP to bring its monthly fixed charge in line with Enbridge's fixed monthly charge.

(b) The portion of customer related costs that would be recovered through the fixed monthly charge if it is increased to $21 per month in 2024 is provided in Table 8-STAFF-70-1.

Table 8-STAFF-70-1
Recovery of Customer Related Costs

		A	B	C	D	E	F
			2020			**2024**	
		R1 Residential	**R1 Commercial**	**R1 Industrial**	**R1 Residential**	**R1 Commercial**	**R1 Industrial**
1	Customer Cost per Customer /month[1]	$27.17	$43.96	$78.69	$27.17	$43.96	$78.69
2	Proposed Fixed Charge	$17.00	$17.00	$17.00	$21.00	$21.00	$21.00
3	% Customer Cost Covered	62.57%	38.67%	21.60%	77.29%	47.77%	26.69%

[1] In forecasting the customer cost per customer/month for 2024, a simplifying assumption has been made that customer growth will equal increase in customer cost such that the cost per customer remains stable.

8-STAFF-71
Reference: **Exhibit 8 / Tab 1 / Schedule 1/ Pg. 7**

Request:

In Table 8.0-5, EPCOR has proposed changes to the Schedule of Miscellaneous and Service Charges. Most of the charges and rates related to service work have been increased.

How do the proposed charges and rates compare to charges for similar services by Enbridge Gas Inc. and the local electric distribution utility? Please provide a table showing the comparison.

Response:

Comparisons of EPCOR's proposed Miscellaneous and Service Charges to Enbridge and ERTH Power (formally Erie Thames Powerlines) can be found in Tables 8-STAFF-71-1 and 8-STAFF-71-2, respectively, below.

Table 8-STAFF-71-1
Schedule of Miscellaneous and Service Charges
ENGLP Aylmer Comparison to Enbridge

	Service	A **Proposed Fee**	B **Enbridge**	**C** **Enbridge Rider G Category Used as Comparator**	D **Difference (A - B)**
1	Service Work				
2	During normal working hours				
3	Minimum charge (up to 60 minutes)	$100.00	$140.00	Labour hourly Charge-Out Rate	($40.00)
4	Each additional hour (or part thereof)	$100.00	$140.00	Labour hourly Charge-Out Rate	($40.00)
5	Outside normal working hours				
6	Minimum charge (up to 60 minutes)	$130.00	$140.00	Labour hourly Charge-Out Rate	($10.00)
7	Each additional hour (or part thereof)	$105.00	$140.00	Labour hourly Charge-Out Rate	($35.00)
8	Miscellaneous Charges				
9	Returned Cheque / Payment	$48.00	$20.00	Cheques Returned Non-Negotiable Charge	$28.00
10	Replies to a request for account information	$25.00	$30.00	Request for Service Call Information	($5.00)
11	Bill Reprint / Statement Print Requests	$20.00	$10.00	Statement of Account Charge	$10.00
12	Consumption Summary Requests	$20.00	$10.00	Statement of Account Charge	$10.00
13	Customer Transfer / Connection Charge	$35.00	$25.00	New Account Charge	$10.00
14	Disconnection and Reconnection Charge	$85.00	$95.00	Activation + Red Lock	($10.00)
15	Inactive Account Charge	ENGLP cost to install service	$70.00	Red Lock Charge	TBD
16	Late Payment Charge	1.5% / month, 19.56% / year	1.5% /month, 19.56% /year	Section F - Payment Conditions	Same
17	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs	$105.00	Residential / Time and Materials for Non-Residential	TBD
18	Installation of Service Lateral	$100 (minimum). Additional if pipe length exceeds length used to set fee.	$140.00	Labour hourly Charge-Out Rate	TBD

Table 8-STAFF-71-2
Schedule of Miscellaneous and Service Charges
ENGLP Aylmer Comparison to ERTH Power

	Service	A Proposed Fee	B ERTH Power	C Service Charge Used as Comparator	D Difference (A - B)
1	Service Work				
2	During normal working hours				
3	Minimum charge (up to 60 minutes)	$100.00	N/A	N/A	N/A
4	Each additional hour (or part thereof)	$100.00	N/A	N/A	N/A
5	Outside normal working hours				
6	Minimum charge (up to 60 minutes)	$130.00	N/A	N/A	N/A
7	Each additional hour (or part thereof)	$105.00	N/A	N/A	N/A
8	Miscellaneous Charges				
9	Returned Cheque / Payment	$48.00	$15.00	Returned Cheque	$33.00
10	Replies to a request for account information	$25.00	N/A	N/A	N/A
11	Bill Reprint / Statement Print Requests	$20.00	N/A	N/A	N/A
12	Consumption Summary Requests	$20.00	N/A	N/A	N/A
13	Customer Transfer / Connection Charge	$35.00	$30.00	Account Set-up / Change of Occupancy	$5.00
14	Disconnection and Reconnection Charge	$85.00	$65.00	Disconnect/Reconnect at Meter - Regular Hours	$20.00
15	Inactive Account Charge	ENGLP cost to install service	N/A	N/A	N/A
16	Late Payment Charge	1.5% / month, 19.56% / year	1.5% / month, 19.56% / year	Late Payment Charge	Same
17	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs	30	Meter Dispute Charge	TBD
18	Installation of Service Lateral	$100 (minimum). Additional if pipe length exceeds length used to set fee.	N/A	N/A	TBD

8-STAFF-72

Reference: **Exhibit 8 / Tab 2 / Schedule 1/ Pg. 1 and Exhibit 3 / Tab 2 /Schedule 1/pg.20**

Request:

The bill impact shown for a typical residential customer uses a volume of 1,780 m^3. However, the average weather corrected consumption for 2020 is 1,920 m^3 for residential customers as determined in the weather normalization calculations.

Please reconcile the two consumption values. Why is the average consumption of 1,920 m^3 not appropriate for bill impact calculations?

Response:

1,920 m3 is the average volume per residential customer. 1780 m3 is the annual volume of a median residential customer. Compared to median volume, average volume per customer is less reflective of a typical customer when the distribution of annual customer consumption is not perfectly symmetrical and is more affected by outliers.

The Table below provides a bill impact for an average residential customer with 1,920 m3 of annual volume.

Table 8-STAFF-72-1
Rates 1 – Residential (Average)

		A Unit	B Bill Determinant	C Current Rate	D Proposed Rate	E Billed Amount with Current Rate	F Billed Amount with Proposed Rate	G Change ($)	H Change (%)
1	Fixed Monthly Rate	$ / month	12	15.50	17.00	186.00	204.00	18.00	9.68%
2	Tier 1 Rate (first 1,000 m3's)	cents / m3	1,908	15.9486	14.9119	304.30	284.52	(19.78)	(6.50%)
3	Tier 2 Rate (> 1,000 m3's)	cents / m3	12	11.3519	12.0146	1.36	1.44	0.08	5.84%
4	Delivery Rates					491.66	489.96	(1.70)	(0.35%)
5	IRM Rebalancing	$ / month	12	1.81	0.00	21.77	0.00	(21.77)	(100.00%)
6	Delivery Rates & IRM Rebalancing					513.43	489.96	(23.47)	(4.57%)
8	PGTVA Rate Rider	cents / m3	1,920	-1.7172	0.1280	-32.97	2.46	35.43	107.46%
9	REDA Rate Rider	$ / month	12	1.50	0.59	18.00	7.03	(10.97)	(60.94%)
10	2019 Shared Tax Changes Rate Rider	$ / month	12	0.11	0.00	1.30	0.00	(1.30)	(100.00%)
11	2018 Shared Tax Changes Rate Rider	$ / month	12	0.03	0.00	0.33	0.00	(0.33)	(100.00%)
12	2018 Unrecovered IRM Adjustment Rate Rider	cents / m3	1,920	0.2221	0.0000	4.26	0.00	(4.26)	(100.00%)
13	**Total Bill Excluding System Gas Fee**					**504.35**	**499.45**	**(4.90)**	**(0.97%)**
14	System Gas Fee	cents / m3	1,920	0.0363	0.0435	0.70	0.84	0.14	19.86%
15	**Total Bill**					**505.05**	**500.29**	**(4.76)**	**(0.94%)**

8-STAFF-73

Reference: **Exhibit 8 / Tab 3 / Schedule 2/ Pgs. 10-11 – Conditions of Service**

Request:

In its Conditions of Service, EPCOR has indicated that all customers will be required to provide a security deposit unless the requirement is waived by EPCOR. Good payment history must be demonstrated for a period of at least one year for residential customers, five years for general service customers and seven years for all other customers.

The security deposit amount is determined based on the average monthly natural gas consumption over the last 12 consecutive months, within the past two years at the specific address where service will be installed. The maximum amount of the security deposit EPCOR may require from a customer shall be 2.5 times the average actual monthly consumption over the past 12 consecutive months or based on an estimate if no consumption record is available. Security deposits on all accounts are reviewed annually to determine if the customer is entitled to a refund or an adjustment is required.

Requests for refund of a security deposit can be made after one year of service for residential customers, five years of service for general service customers and seven years for all other customers.

(a) Please indicate whether the security deposit policy applies to all existing customers or those that are moving or obtaining new service.

(b) Security deposits on all accounts are reviewed annually to determine if the customer is entitled to get a refund on the security deposit. Please provide the number of accounts that have been reviewed after EPCOR acquired the utility and the number of customers that have been refunded their security deposit or received a corresponding bill adjustment.

(c) To the best of EPCOR's knowledge, is the security deposit policy of EPCOR largely in line with Union Gas (now owned by Enbridge Gas Inc.)? If no, please outline the major differences.

(d) The deposit amount for Union Gas non-residential customers is a maximum of the three highest consecutive months' usage history or $500 if there is no consumption information available. The deposit is refunded with interest after five years of exhibiting financial stability through a good payment history. Why has EPCOR's refund policy been extended to seven years for other customers (those that are not residential or general service)? Would EPCOR consider reducing the security deposit holding period from seven to five years?

(e) Is EPCOR seeking OEB approval for the revised Conditions of Service?

Response:

(a) The security deposit policy applies to all existing ENGLP Aylmer customers. Customers including those that are moving or obtaining services can have the security deposit waived if they:

- Are a General Service Customer and meet ENGLP's credit requirements;
- Can provide a letter of reference from any natural gas or electricity utility in Canada confirming good payment history;
- Have moved, and the customers previous ENGLP account has a good payment history; or
- Have requested the security deposit requirement be waived and are an eligible low-income customer.

(b) ENGLP reviewed 318 accounts for security deposit return entitlement since acquiring the utility on November 01, 2017. As of March 30, 2019, 161 customers were refunded their security deposit. Table 8-STAFF-73-1 below summarizes the monthly security deposit reviews, returned and retained.

Table 8-STAFF-73-1
Summary of Monthly Security Deposit Reviewed, Returned and Retained

	Date	A **Accounts Reviewed**	B **Deposits Returned**	C **Deposits Retained**
1	Nov 2017	32	16	16
2	Dec 2017	23	10	13
3	Jan 2018	18	9	9
4	Feb 2018	15	10	5
5	Mar 2018	17	10	7
6	April 2018	18	11	7
7	May 2018	17	6	11
8	June 2018	22	11	11
9	July 2018	20	10	10
10	Aug 2018	12	8	4
11	Sept 2018	19	12	7
12	Oct 2018	25	10	15
13	Nov 2018	31	15	16
14	Dec 2018	22	10	12
15	Jan 2019	7	4	3
16	Feb 2019	8	3	5
17	Mar 2019	12	6	6
18	**TOTAL**	**318**	**161**	**157**

(c) ENGLP Aylmer's security deposit policy is largely in line with Enbridge Gas Inc. deposit policy detailed in Enbridge Gas Inc. January 01, 2019 Conditions of Service.[1] Table 8-STAFF-73-2 below compares ENGLP Aylmer and Enbridge Gas conditions for security deposits.

[1] Enbridge Gas Inc. CONDITIONS OF SERVICE for Union Rate Zones , January 01, 2019 , Sec. 4.12 Security Deposits pg. 21-22

Table 8-STAFF-83-2
Comparison of ENGLP Aylmer and Enbridge Gas Conditions for Security Deposits

		A **ENGLP**	B **Enbridge Gas**	C **Notes**
1	Deposit applies to new customers or where customers cannot assure payment	✓	✓	
2	Deposit can be waived with proof of good payment history, letter of reference or qualifies for LEAP	✓	✓	
3	Deposit can be waived with Letter of Guarantee, Letters of Credit for Non Residential Customers	✓	✓	
4	Deposit refund for good payment history for Residential Customer	12 Months	12 Months	
5	Deposit returned for good payment history for General Service Customer	5 years	5 years	Enbridge Gas Inc. categorizes: "Non-Residential" or "Residential" customer.
6	Deposit returned for good payment history for all other Customers	7 years	5 years	Enbridge Gas Inc. categorizes: "Non-Residential" or "Residential" customer.

(d) ENGLP Aylmer has three categories of deposit terms comprised of: One year for Residential, Five years for General Service customers and Seven years for all other customers. ENGLP Aylmer classifies General Service customers as those who consume less than 100,000 m^3 annually. All customers who exceed an annual consumption of 100,000 $m^3$are classified to the seven year deposit term category.

ENGLP Aylmer's security deposit condition of service is to protect both ENGLP Aylmer and its customers from increased rates resulting from non-paying customers. Compared to Enbridge Gas Inc., the total number of customers of ENGLP Aylmer is small which impedes its ability to endure or spread the impact across customers, especially if a large consumption customer should default on their payment. ENGLP Aylmer does not support the reduction of the security deposit from seven years to five years for "all other customers" (i.e., large consumption customers) as this would increase the large customer default risk and potentially transfer this burden to smaller consuming customers and ENGLP Aylmer.

(e) ENGLP Aylmer is not seeking approval of the Conditions of Service. As there have been a number of clarification changes and additions to the Conditions of Service from the last version filed with the Board by NRG, ENGLP has provided its 2020 Conditions of Service as part of this Application for information.

ENGLP Aylmer will implement the Conditions of Service as filed, however, it notes that it is reviewing the recent amendments of the GDAR and will update the Conditions of Service, where necessary. In requesting approval of the Schedule of Miscellaneous and Service Charges included on page 16 of Exhibit 8, Tab 2, Schedule 4, ENGLP is seeking approval from the Board for the customer charges in the Conditions of Service to the extent the Board considers any of the charges contained in the Schedule of Miscellaneous and Service Charges to be charges for the distribution of gas.

9-STAFF-74

Reference: **Exhibit 9/ Tab 1/ Schedule 1/Pg. 3**

Request:

Please provide the updated audited 2018 account balances, rate rider and bill impact summary.

Response:

ENGLP notes that these balances do not form part of ENGLP's audited financial statements for its Aylmer operations as ENGLP does not report under IFRS 14. However, the balances have been audited by ENGLP's auditors using specified audit procedures to ensure the reasonability of the amounts. The report from ENGLP's auditors with respect to these balances has been provided as 9-STAFF-74 Attachment 1. The updated continuity schedules have been provided as 9-STAFF-74 Attachment 2, and in Excel format in the file named 9-STAFF-74 Attachment 3.

In accordance with the filing requirements, ENGLP confirms that the balances proposed here for disposition are consistent with the account balances it will report in the 2018 year-end RRR.

The updated audited 2018 account balances proposed for disposition and the associated rate riders are provided in the tables below (note that all balances proposed for disposition are debit balances).

Table 9-STAFF-74-1
PGTVA 1-5

		A **Unit**	B **Amount**
1	PGTVA 1-5 audited Dec 31, 2018 balance	$	35,466
2	PGTVA 1-5 audited carrying charges as of Dec. 31, 2018	$	196
3	PGTVA 1-5 forecasted interest from Dec 31, 2018 through Dec 31, 2019	$	797
4	**Total Disposition Amount**	$	**36,459**
5	Total Forecasted Volume for Rate Classes 1 - 5	m3	28,475,446
6	**Proposed 12 Month Volumetric Rate Rider for Rate Classes 1 - 5**	cents / m3	**0.1280**

Table 9-STAFF-74-2
PGTVA 6
($)

		A **Amount**
1	PGTVA 6 audited Dec 31, 2018 balance	178,809
2	PGTVA 6 audited carrying charges as of Dec. 31, 2018	2,132
3	PGTVA 6 forecasted interest from Dec 31, 2018 through Dec 31, 2019	4,019
4	**Total Projected Disposition Amount**	**184,960**
5	**Proposed Fixed Monthly Rate Rider**	**15,413.33**

Table 9-STAFF-74-3
REDA Amount Proposed for Disposal
($)

		A **DSM**	B **All Other**	C **Total**
1	REDA audited Dec 31, 2018 balance[1]	2,803	61,973	64,776
2	REDA audited carrying charges as of Dec. 31, 2018	37	785	822
3	REDA forecasted interest from Dec 31, 2018 through Dec 31, 2019	63	1,393	1,456
4	**Total Disposition Amount**	**2,903**	**64,151**	**67,054**

[1] A number of invoices for legal costs related to proceeding EB-2017-0108 were inadvertently omitted in the estimated balances in the original application and are now included in the audited balances.

Table 9-STAFF-74-4
Proposed REDA Rate Riders

	A **Unit**	B **Row Sum**	C **Rate 1 - Residential**	D **Rate 1 - Commercial**	E **Rate 1 - Industrial**	F **Rate 2**	G **Rate 3**	H **Rate 4**	I **Rate 5**	J **Rate 6**
1 Average Connection Count	Cx	9,538	8,877	494	68	50	6	38	4	1
2 Allocation for DSM	%	100.00%	93.08%	5.18%	0.71%	0.52%	0.06%	0.40%	0.04%	0.00%
3 Allocation for Other REDA	%	100.00%	93.07%	5.18%	0.71%	0.52%	0.06%	0.40%	0.04%	0.01%
4 DSM	$	2,903	2,702	150	21	15	2	12	1	0
5 Other REDA	$	64,151	59,705	3,323	457	336	40	256	27	7
6 Sum	$	67,054	62,407	3,473	478	352	42	267	28	7
7 **Rate Rider / month**	**$ / month**		**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.59**	**0.56**

The updated bill impact summary reflecting the proposed rate riders resulting from the audited December 31, 2018 balances is as follows:

Table 9-STAFF-74-5
Proposed Rate Rider Bill Impact Summary

		A **Annual PGTVA Amount ($)**	B **Annual REDA Amount ($)**	C **Annual Bill Amount without Rate Riders (Current Rates) ($)**	D **Annual Bill Amount with Rate Riders (Current Rates) ($)**	E **Change ($)**	F **Change (%)**
1	Rate 1 - Residential	2.28	7.03	491.69	501.00	9.31	1.89%
2	Rate 1 - Commercial	5.19	7.03	853.94	866.16	12.22	1.43%
3	Rate 1 - Industrial	15.74	7.03	2,102.32	2,125.09	22.77	1.08%
4	Rate 2	18.31	7.03	2,830.16	2,855.50	25.34	0.90%
5	Rate 3	151.02	7.03	94,738.48	94,896.53	158.05	0.17%
6	Rate 4	20.99	7.03	2,454.55	2,482.58	28.02	1.14%
7	Rate 5	218.13	7.03	15,417.20	15,642.37	225.16	1.46%
8	Rate 6	184,960.00	6.73	1,133,887.44	1,318,854.17	184,966.73	16.31%

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ACCOUNTANT'S REPORT ON APPLYING SPECIFIED AUDITING PROCEDURES IN RESPECT OF THE SPECIFIC DEFERRAL ACCOUNT BALANCES

To: EPCOR Natural Gas Limited Partnership

As specifically agreed, we have performed the auditing procedures described in appendix A over the deferral account schedule for PGTVA 1-5, PGTVA 6 and REDA, to assist EPCOR Natural Gas Limited Partnership (the "Company") to comply with the requirements of the Ontario Energy Board (OEB) for the period from October 1, 2017 to December 31, 2018.

This engagement to apply agreed-upon auditing procedures was performed in accordance with Canadian Standards on Related Services 9100, Reports on the Results of Applying Specified Auditing Procedures. We make no representation regarding the sufficiency of the procedures described in Appendix A either for the purpose for which this report has been requested or for any other purpose.

The procedures in Appendix A do not constitute an audit of the deferral account schedule and, therefore, we express no opinion on the information in the schedule for the period from October 1, 2017 to December 31, 2018. Had we performed additional procedures, other matters might have come to our attention that we would have reported to you.

This letter is for use in assessing the Company's deferral account balances for PGTVA 1-5, PGTVA 6 and REDA from October 1, 2017 to December 31, 2018, and is not intended to be and should not be used for any other purpose.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

London, Ontario

April 9, 2019

APPENDIX A

1. We obtained the deferral account activity for PGTVA 1-5 and PGTVA 6 from October 1, 2017 to December 31, 2018 and recalculated the schedules to ensure their mathematical accuracy.

2. For PGTVA 1-5 and PGTVA 6, we verified a sample of 6 months of the total transportation cost and the volumes transported with Union Gas invoices.

3. For PGTVA 1-5 and PGTVA 6, we verified the reference price to the specific OEB filing for the entire period.

4. We obtained the deferral account activity for the REDA account from October 1, 2017 to December 31, 2018 and verified its mathematical accuracy.

5. For the REDA account, we obtained all of the invoices for each month of activity and compared them to the amounts claimed in the schedule. For each selection, we reviewed the OEB reference number to ensure that the cost claimed matched the purpose of the deferral account.

Purchased Gas Transportation Variance Account Continuity Schedule

	CARRY FORWARD 2017 SEPT	2017 OCT	2017 NOV	2017 DEC	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC	Projected interest 2019 Jan-Dec
PGTVA 1-5																	
Transportation Cost																	
Union Gas - Delivery	-	69,218.78	163,279.78	153,747.47	183,775.88	114,514.98	117,634.79	80,912.63	43,026.27	38,732.82	14,545.54	25,252.69	40,791.93	4,151.43	8,764.73	6,296.65	
Union Gas - Adjmts	-	(58,971.99)	(135,764.37)	(143,276.27)	(156,536.82)	(108,118.65)	(111,064.19)	(76,784.27)	(40,830.59)	(36,647.02)	(13,803.38)	(23,964.24)	(38,710.62)	(705.32)	-	-	
Union Gas - Demand	-	42,533.16	42,533.16	42,533.16	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	44,872.58	52,216.75	52,216.75	
Total Transportation Cost	-	52,779.95	70,048.57	53,004.36	72,111.64	51,268.91	51,443.18	49,000.94	47,068.26	46,958.38	45,614.74	46,161.03	46,953.89	48,318.69	60,981.48	58,513.40	
Volumes Transported (m3)		2,074,795.40	4,212,766.30	4,432,980.40	4,825,964.30	3,349,882.90	3,452,007.70	2,411,973.90	1,329,119.40	1,198,323.40	509,811.30	815,056.30	1,248,908.30	2,729,589.00	5,027,135.00	4,083,031.10	
Average Cost ($/m3)		0.025439	0.016628	0.011957	0.014942	0.015305	0.014902	0.020316	0.035413	0.039187	0.089474	0.056635	0.037596	0.017702	0.012130	0.014331	
Reference Price - corrected per EB-2017-0215		0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	0.018339	
Rate Difference		(0.007100)	0.001711	0.006382	0.003397	0.003034	0.003437	(0.001977)	(0.017074)	(0.020848)	(0.071135)	(0.038296)	(0.019257)	0.000637	0.006209	0.004008	
PGTVA 1-5	-	(14,730.28)	7,209.35	28,292.07	16,391.72	10,164.59	11,863.19	(4,767.75)	(22,693.54)	(24,982.33)	(36,265.31)	(31,213.71)	(24,050.16)	1,739.24	31,211.15	16,365.31	
Disposition as per EB-2018-0235 Decision and Rate Order	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(399,098.00)	
Balance	399,098.00	384,367.72	391,577.07	419,869.14	436,260.86	446,425.45	458,288.64	453,520.89	430,827.35	405,845.03	369,579.71	338,366.00	314,315.84	316,055.08	347,266.23	(35,466.46)	
PGTVA 1-5 Interest																	
Interest rate		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	2.17%	2.17%	2.17%	
Interest	-	498.87	480.46	489.47	524.84	545.33	558.03	721.80	714.30	678.55	639.21	582.09	532.93	568.39	571.53	627.97	(797)
Disposition as per EB-2018-0235 Decision and Rate Order	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(29,822.00)	
Interest Adjustment Related to December Disposition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(8,929.80)	
Balance	29,822.00	30,320.87	30,801.33	31,290.80	31,815.64	32,360.97	32,919.00	33,640.80	34,355.10	35,033.65	35,672.86	36,254.95	36,787.88	37,356.27	37,927.80	(196.03)	
Total PGTVA 1-5 and Interest	**428,920.00**	**414,688.59**	**422,378.40**	**451,159.94**	**468,076.50**	**478,786.42**	**491,207.64**	**487,161.69**	**465,182.45**	**440,878.68**	**405,252.57**	**374,620.95**	**351,103.72**	**353,411.35**	**385,194.03**	**(35,662.49)**	
PGTVA 6 (IGPC)																	
Transportation Cost																	
Union Gas - Delivery IGPC	-	85,344	106,826	99,781	109,566	93,382	103,063	72,554	103,359	97,001	98,148	100,202	74,374	-	-	-	
Union Gas - Adjmts IGPC	-	(70,295)	(99,550)	(92,985)	(103,446)	(88,166)	(97,307)	(68,852)	(98,085)	(92,052)	(93,140)	(95,089)	(70,579)	-	-	-	
Union Gas - Demand IGPC	-	29,868	29,868	29,868	31,511	31,511	31,511	31,511	31,511	31,511	49,157	49,157	49,157	-	-	-	
Total Transportation Cost	-	44,917	37,144	36,664	37,631	36,727	37,268	35,213	36,784	36,460	54,165	54,270	52,952	-	-	-	
IGPC Volumes Transported (m3)		2,396,902	3,000,220	2,802,354	3,117,621	2,657,118	2,932,603	2,075,043	2,956,072	2,774,237	2,807,031	2,865,774	2,127,092				
Actual Price		0.018740	0.012380	0.013083	0.012070	0.013822	0.012708	0.016970	0.012444	0.013142	0.019296	0.018937	0.024894	0.000000	0.000000	0.000000	
Reference Price - corrected per EB-2017-0215		0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	0.009885	
Rate Difference		(0.008855)	(0.002495)	(0.003198)	(0.002185)	(0.003937)	(0.002823)	(0.007085)	(0.002559)	(0.003257)	(0.009411)	(0.009052)	(0.015009)	0.009885	0.009885	0.009885	
PGTVA 6 (IGPC)	-	(21,225)	(7,486)	(8,962)	6,812.00	(10,461)	(8,279)	(14,702)	(7,565)	(9,036)	(26,417)	(25,941)	(31,926)	-	-	-	
Disposition as per EB-2018-0235 Decision and Rate Order	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(500,577)	
Balance	500,577	479,352	471,867	462,905	456,093	445,632	437,353	422,651	415,087	406,051	379,634	353,693	321,768	321,768	321,768	(178,809)	
PGTVA 6 (IGPC) Interest																	
Interest	-	626	599	590	579	570	557	689	666	654	640	598	557	582	582	582	(4,019)
Disposition as per EB-2018-0235 Decision and Rate Order	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43,735)	
Interest Adjustment Related to December Disposition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11,200)	
Balance	43,735	44,361	44,960	45,550	46,128	46,698	47,256	47,944	48,610	49,264	49,903	50,501	51,058	51,640	52,222	(2,132)	
Total PGTVA 6 (IGPC) and Interest	**544,312**	**523,713**	**516,827**	**508,455**	**502,221**	**492,330**	**484,609**	**470,596**	**463,697**	**455,315**	**429,538**	**404,194**	**372,826**	**373,408**	**373,990**	**(180,941)**	

Regulatory Expense Deferral Account Continuity Schedule

Monthly Interest Rate		1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	2.17%	2.17%	2.17%	2019 Projected interest
Regulatory Expense Deferral Account (REDA)	**Carry forward 30-Sep-17**	**31-Oct-17**	**30-Nov-17**	**31-Dec-17**	**31-Jan-18**	**28-Feb-18**	**31-Mar-18**	**30-Apr-18**	**31-May-18**	**30-Jun-18**	**31-Jul-18**	**31-Aug-18**	**30-Sep-18**	**31-Oct-18**	**30-Nov-18**	**31-Dec-18**	**Jan-Dec**
REDA and IFRS Costs UP to Sep 30, 2017 (Approved for Dispostion in EB-2018-0235)																	
EB-2008-0346 - Cost Awards for Guidelines for DSM	1,538	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,538)	
IFRS Matters	3,686	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,686)	
Eng. Study Terms of Reference	9,416	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(9,416)	
Low Income - EB 2010-0280	20,838	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20,838)	
Steering Committee (System Integrety Study)	72,516	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(72,516)	
2014-0199 - Review of QRAM Process	23,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,085)	
2014-0289 Natural Gas Market Review	13,802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(13,802)	
DSM Account	3,532	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,532)	
Other REDA Items	4,113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,113)	
Subtotal REDA and IFRS Approved for Disposition in EB-2018-023!	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**152,525**	**-**	
REDA CostsSince October 1, 2017																	
EB-2015-0245 DSM																	
Ontario Energy Board - #CA18119Q1003		-	-	-	-	-	-	2,803	-	-	-	-	-	-	-	-	
Sub-total DSM		**-**	**-**	**-**	**-**	**-**	**-**	**2,803**	**2,803**	**2,803**	**2,803**	**2,803**	**2,803**	**2,803**	**2,803**	**2,803**	
EB-2015-0040 Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs																	
EB-2015-0040 - Ontario Energy Board - #CA1718Q4003		-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	
		-	**-**	**-**	**-**	**31**	**31**	**31**	**31**	**31**	**31**	**31**	**31**	**31**	**31**	**31**	
EB 2017-0183 Review of Customer Service Rules																	
EB-2017-0183 - Ontario Energy Board - #CA1819Q2003		-	-	-	-		-	-	-	-	132	-	-	-	-	-	
		-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**132**	**132**	**132**	**132**	**132**	**132**	
EB-2017-0108 Overlapping CPCN's																	
Osler, Hoskin & Harcourt LLP - #12109615		-	-	-	22,185	-	-	-	-	-	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12118810		-	-	-	-	4,911	-	-	-	-	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12128394		-	-	-	-	-	4,627	-	-	-	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12138504		-	-	-	-	-	-	4,083	-	-	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12148497		-	-	-	-	-	-	-	11,632	-	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12165876		-	-	-	-	-	-	-	-	3,012	-	-	-	-	-	-	
Osler, Hoskin & Harcourt LLP - #12175763		-	-	-	-	-	-	-	-	-	-	-	4,191	-	-	-	
Osler, Hoskin & Harcourt LLP - #12216731		-	-	-	-	-	-	-	-	-	-	-	-	-	3,368	-	
Osler, Hoskin & Harcourt LLP - #12227599		-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,801	
sub-total		**-**	**-**	**-**	**22,185**	**27,096**	**31,723**	**35,806**	**47,438**	**50,451**	**50,451**	**50,451**	**54,642**	**54,642**	**58,009**	**61,810**	
Subtotal REDA Since October 1, 2017		**-**	**-**	**-**	**22,185**	**27,127**	**31,755**	**38,640**	**50,272**	**53,284**	**53,416**	**53,416**	**57,607**	**57,607**	**60,975**	**64,775**	
Total Balance in REDA	**152,525**	**152,525**	**152,525**	**152,525**	**174,710**	**179,652**	**184,280**	**191,165**	**202,797**	**205,809**	**205,941**	**205,941**	**210,132**	**210,132**	**213,500**	**64,775**	
REDA Interest Expense																	
Interest on carry forward																	
Interest on Approved Costs until approved disposition		191	191	191	191	191	191	240	240	240	240	240	240	276	276	276	
Cumulative Interest on Approved Costs until approved disposition	5,750	5,941	6,131	6,322	6,513	6,703	6,894	7,134	7,375	7,615	7,855	8,095	8,335	8,611	8,887	9,163	
Disposition as per EB-2018-0235 Decision and Rate Order		-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,750)	
Interest Adjustment Related to December Disposition		-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,413)	
REDA Interest Expense																	
DSM Interest Expense		-	-	-	-	-	-	-	4	4	4	4	4	5	5	5	63
DSM Cumulative Interest Balance		-	-	-	-	-	-	-	4	9	13	18	22	27	32	37	
Overlapping CPCN's and Other REDA interest		-	-	-	-	28	34	50	56	75	80	80	80	99	99	105	1,393
Cumulative Interest Balance		-	-	-	-	28	62	112	168	243	322	402	482	581	680	785	
Total Interest Expense	**5,750**	**5,941**	**6,131**	**6,322**	**6,513**	**6,731**	**6,956**	**7,246**	**7,547**	**7,866**	**8,191**	**8,515**	**8,839**	**9,219**	**9,599**	**822**	
Total REDA and interest	**158,275**	**158,466**	**158,656**	**158,847**	**181,223**	**186,384**	**191,235**	**198,411**	**210,344**	**213,676**	**214,132**	**214,456**	**218,971**	**219,351**	**223,099**	**65,598**	

9-STAFF-75

Reference: **Exhibit 9 / Tab 1 / Schedule / Pg.8**

Request:

The Transportation Service Charge Deferral Account was established in 2010 to record the revenues recovered through the transmission service charges, including the Transmission Administrative Charge and the Transportation Rate, from natural gas producers that sold gas into Union Gas' system via EPCOR's distribution system. The charges proposed for 2020 are the same as established in 2010.

(a) Please explain how the charges were derived.

(b) Why has EPCOR proposed the same charges that were established over nine years ago?

Response:

(a) Per the Board's Decision and Order for Proceeding EB-2010-0018 dated December 6, 2010, these charges were based on the charges paid by NRG Corp. to Greentree Gas & Oil Ltd. ("Greentree") at the time for transporting gas through Greentree's system to Union.[1]

(b) ENGLP has proposed the same charge for 2020 as ENGLP is not in a position to determine or justify a different rate for this service. ENGLP does not have a comparable reference price to use to establish a new market-based rate nor is ENGLP able to justify a cost-based rate for these services given that these services have not been provided for a number of years. ENGLP is not expecting any gas producers to use its distribution system to transport gas into Enbridge Gas' Union South system.

[1] OEB Decision and Order EB-2010-0018 dated December 6, 2010, pgs. 18-19.

9-STAFF-76
Reference: **Exhibit 9/ Tab 1/ Schedule 1/Pg. 11**

Request:

The balance in the Rebalancing deferral account was approved for disposition and transferred out.

(a) Please explain what account the balance was transferred to.

(b) For all deferral and variance accounts where an amount has been approved for disposition, what is the accounting treatment for the approved amounts (e.g. are the approved amounts transferred to a separate account)?

(i) Please confirm that if there is any under/over refund/collection of amounts approved for disposition, there is no true up to the approved amount (i.e. the equivalent of Account 1595 for electricity distributors)? If not confirmed, please explain.

(ii) Historically, has the under/over collection/refunds been material?

Response:

(a) The balance from the Rebalancing deferral account that was approved for disposition was transferred to USoA account 179.90 'Approved deferral/variance disposal' account.

(b) When balances have been approved for disposition they are transferred to the 179.90 account by recording the following entry:

Debit/Credit - Deferral/variance account	(179.XX account)
Credit/Debit – Approved deferral/variance disposal	(179.90 account)

(i) ENGLP will account for account 179.90 in the same manner as account 1595 for electricity distributors by recording a debit/credit for the appropriate sub-account (principal balances, carrying charges or carrying charges for net principal). To the extent that an approved amount is over or under collected once the approved period for collection/refund of the approved amount has finished, ENGLP will bring any remaining amounts forward to the OEB for disposition at a future proceeding.

(ii) There has not been any material under/over collection/refunds since ENGLP acquired the assets. ENGLP cannot confirm for periods during NRG's ownership given the limited historical financial records.

9-STAFF-77

Reference: **Exhibit 9/ Tab 1/ Schedule 1/Pg. 18**
Exhibit 2/ Tab 1/ Schedule 1/Pg. 6

Request:

(a) EPCOR proposes to establish a Loss on Disposal of Meters deferral account to record forecasted disposal losses in 2020. Please explain why the forecasted loss is not included in the revenue requirement but requested to be included in a deferral account.

(b) Please explain whether EPCOR has included any gains and losses from asset disposals in revenue requirement. If yes, please indicate where in the application. If no, please explain why not.

Response:

(a) The forecast loss on disposal of $162,461 is a material "one time" cost and ENGLP believes that it would not be appropriate to include this amount in the revenue requirement as it would be included in base rates and then notionally recovered in each year of the IRM period, resulting in an overcharge to customers.

ENGLP has requested a deferral account to track disposal losses in order to establish a more accurate value associated with the cost of the write-off and to provide a clear line of sight as to the rate impact through a rider. ENGLP will rely on audited balances as the basis of disposition, which will be more accurate than forecasted balances.

(b) No gains or losses from asset disposals are included in the revenue requirement. The loss on disposal of meters is proposed to be tracked in the requested deferral account as described in (a) above.

9-STAFF-78

Reference: **Exhibit 9/ Tab 1/ Schedule 1/Pg. 19**
Exhibit 10/ Tab 1/ Schedule 1/Pg. 8

Request:

EPCOR proposes to establish a Recovery of Income Tax deferral account to record differences between taxes in the revenue requirement and actual taxes paid. EPCOR expects the amount to exceed the materiality threshold.

(a) Please explain the basis of this expectation, including the main factors leading to an increase in taxes in future years.

(b) Please provide an approximate calculation of the future taxes payable.

(c) Please explain why EPCOR is proposing to establish the Recovery of Income Tax deferral account and have a separate mechanism to record impacts of legislated tax changes during the IR period instead of having just one deferral account to capture all tax impacts.

Response:

(a) As noted in response to 1-STAFF-7, the CCA calculations presented in Table 4.5.2-1 in the Application inadvertently included an increase to the UCC balances to fair value. Amending the CCA calculation accordingly has increased income tax in the revenue requirement to expected levels. As a result of this change, ENGLP no longer expects the income taxes in future years to be materially different from what is included in the revised revenue requirement as reflected in 9-STAFF-78 Attachment 2. Also, as described in response to 4-STAFF-59, ENGLP has updated the calculation of taxes payable to reflect deemed interest expense.

In addition to the changes made to the income tax calculation noted above, ENGLP has proposed other updates to the Application based on information provided in the responses to various interrogatories and/or to adjust for items found to be incorrectly calculating in the model. All responses to the interrogatories reflect the proposed updates unless otherwise specifically indicated in the response. A list of the updates to the Application and the resulting changes to the revenue requirement are provided for reference in 9-STAFF-78 Attachment 1. ENGLP has also provided the updated revenue requirement, revenue sufficiency/deficiency and revenue to cost ratios, updated bill impact summaries, summary of proposed changes to distribution rates, and updated rate schedules in 9-STAFF-78 Attachment 2 through 5.

(b) Based on the adjustment as noted in ENGLP’s response to (a) above, ENGLP no longer expects the income taxes in future years to be materially different from what is included in the revised revenue requirement.

(c) As noted in ENGLP’s response to (a) above, ENGLP no longer expects the income taxes in future years to be materially different from what is now included in the revised revenue requirement. Accordingly, the Recovery of Income Tax Deferral Account (“RITDA”) originally proposed is no longer required. As such, ENLGP is proposing to remove the request to establish the RITDA.

Summary of Changes to 2020 Revenue Requirement:

The table below provides a summary of the proposed changes to the revenue requirement and reconciles the $87,968 increase in the revenue requirement from ENGLP's Application filed January 31, 2019 to the current revised revenue requirement.

Table 1
Changes to 2020 Revenue Requirement
($)

	Item	**A**
1	Revenue Requirement filed January 31, 2019	6,652,600
2	Changes to income tax (see 1-STAFF-07 & 4-STAFF-59)	146,786
3	Updated capital additions to reflect 2018 actuals & updates to depreciation calculations[1]	3,937
4	Adjusted 2019 and 2020 capital expenditures (see 2-STAFF-24 & 2-VECC-12)	(27,844)
5	Updated Other Revenue projection (see 3-STAFF-36)	(34,911)
6	**Revised Revenue Requirement**	**6,740,568**

[1] Cost of service model was incorrectly calculating depreciation expense for some items which have now been updated.

Proposed Revenue Requirement

ENGLP is proposing a revenue requirement for the 2020 Test Year of $6,740,568.

Table 1
Summary of 2020 Revenue Requirement
($)

	Description	A **2020 Test**
1	Operation and Maintenance	4,046,256
2	Depreciation and Amortization	1,130,904
3	Property Taxes	632,000
4	Income Taxes	151,896
5	Interest Expense	362,904
6	Return on Equity	575,887
7	Cost of Service Prior before Revenue Offsets	6,899,847
8	less: Other Revenue	(147,778)
9	less: System Gas Fee	(11,501)
10	Revenue Requirement	**6,740,568**

Revenue Sufficiency/Deficiency

ENGLP has determined that the revenue sufficiency for the 2020 Test Year is $264,299. The cost drivers for the revenue sufficiency are outlined in the table below.

Table 2
Cost Drivers of Revenue Sufficiency
($)

	Description	A **2020 Revenue at Existing Rates**	B **2020 Proposed Revenue Requirement**	C **Variance**
1	Transportation Costs	700,200	675,547	(24,653)
2	Distribution OM&A	3,360,306	3,359,208	(1,098)
3	Depreciation and Amortization	1,334,155	1,130,904	(203,251)
4	Property Taxes	627,917	632,000	4,083
5	Income Taxes	157,265	151,896	(5,369)
6	Return on Rate Base	942,214	938,791	(3,423)
7	Other Revenue	(117,190)	(147,778)	(30,588)
8	**Total**	**7,004,867**	**6,740,568**	**(264,299)**

Distribution Revenue to Cost Ratios

The Table below provides the revenue to cost ratios for all customers at the updated revenue requirement.

Table 3
Distribution Revenue to Cost Comparison (Excluding commodity)
($)

	A **Total**	B **Rate 1**	C **Rate 1 - Residential**	D **Rate 1 - Commercial**	E **Rate 1 - Industrial**	F **Rate 2**	G **Rate 3**	H **Rate 4**	I **Rate 5**	J **Rate 6**
1 Proposed Revenue	6,740,568	5,334,035	4,349,614	749,731	234,690	160,079	171,084	147,849	65,767	861,754
2 Cost	6,740,568	5,321,018	4,442,792	707,779	170,447	161,342	183,721	171,835	112,707	789,945
3 Over (Under) Contribution	0	13,016	-93,178	41,952	64,242	-1,263	-12,637	-23,986	-46,940	71,809
4 Proposed Revenue to Cost Ratio	1.00	1.00	0.98	1.06	1.38	0.99	0.93	0.86	0.58	1.09
5 EB-2010-0018 Approved	0.98	0.99	0.94	1.47	0.72	0.37	0.93	1.14	0.61	1.06

Bill Impact Summaries

Table 8.1-1
Summary of Annual Distribution Rate Impacts (Typical)

	Rate Class	A Annual Bill Current Rates	B Annual Bill Proposed Rates	C Change ($)	D Change (%)
1	Rate 1 - Residential	469.92	469.47	(0.00)	-0.10%
2	Rate 1 - Commercial	832.18	808.17	(0.02)	-2.88%
3	Rate 1 - Industrial	2,080.55	1,995.45	(0.09)	-4.09%
4	Rate 2	2,691.46	2,691.54	0.00	0.00%
5	Rate 3	93,609.24	93,613.69	0.00	0.00%
6	Rate 4	2,283.44	2,452.88	0.17	7.42%
7	Rate 5	14,922.42	16,353.40	1.43	9.59%
8	Rate 6	1,133,887.44	861,754.45	(272.13)	-24.00%

Table 8.1-2
Summary of Annual Distribution Rate Impacts (10th Percentile)

	Rate Class	A Annual Bill Current Rates	B Annual Bill Proposed Rates	C Change ($)	D Change (%)
1	Rate 1 - Residential	264.28	277.19	0.01	4.89%
2	Rate 1 - Commercial	304.53	314.82	0.01	3.38%
3	Rate 1 - Industrial	551.97	546.18	(0.01)	-1.05%
4	Rate 2	437.55	467.49	0.03	6.84%
5	Rate 3	9,645.92	9,948.98	0.30	3.14%
6	Rate 4	968.06	1,030.16	0.06	6.42%
7	Rate 5	6,498.74	7,129.47	0.63	9.71%
8	Rate 6	1,133,887.44	861,754.45	(272.13)	-24.00%

Table 1
Summary of Proposed Changes to Distribution Rates

	Rate Class	A Rate Block	B Unit	C Current Rates	D Proposed Rates	E Difference
1	Rate 1	Fixed Monthly Rate	$ / month	15.50	17.00	1.50
2		Tier 1 Rate (first 1,000 m3's)	cents / m3	15.9486	14.9119	(1.0367)
3		Tier 2 Rate (> 1,000 m3's)	cents / m3	11.3519	12.0146	0.6627
4	Rate 2	Fixed Monthly Rate	$ / month	17.25	20.00	2.75
5		April - October				
6		Tier 1 (First 1,000 m3 per month)	cents / m3	17.2765	17.0476	(0.2289)
7		Tier 2 (Next 24,000 m3 per month)	cents / m3	9.4826	9.3570	(0.1256)
8		Tier 3 (Over 25,000 m3 per month)	cents / m3	6.1698	6.7868	0.6170
9		November - March				
10		Tier 1 (First 1,000 m3 per month)	cents / m3	21.7767	21.4882	(0.2885)
11		Tier 2 (Next 24,000 m3 per month)	cents / m3	15.6960	15.4880	(0.2080)
12		Tier 3 (Over 25,000 m3 per month)	cents / m3	15.2899	15.2899	0.0000
13	Rate 3	Fixed Monthly Rate	$ / month	172.50	200.00	27.50
14		Firm Demand	cents / m3 / month	29.0974	29.0974	0.0000
15		Firm Delivery	cents / m3	4.3127	4.0367	(0.2760)
16	Rate 4	Fixed Monthly Rate	$ / month	17.25	17.25	0.00
17		April - December				
18		Block 1 (First 1,000 m^3 per month)	cents / m3	17.1487	18.5480	1.3993
19		Block 2 (Over 1,000 m^3 per month)	cents / m3	10.5218	11.3804	0.8586
20		January - March				
21		Block 1 (First 1,000 m^3 per month)	cents / m3	21.8770	23.6622	1.7852
22		Block 2 (Over 1,000 m^3 per month)	cents / m3	16.9052	18.2847	1.3795
23	Rate 5	Fixed Monthly Rate	$ / month	172.50	190.00	17.50
24		Firm Delivery	cents / m3	7.5439	8.2606	0.7167
25	Rate 6	Fixed Monthly Rate	$ / month	94,490.62	71,812.87	(22,677.75)

EPCOR Natural Gas LP
Proposed Rate Schedules
EB-2018-0336
Effective: January 1, 2020

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 1 - General Service Rate

Rate Availability

The entire service area of the Company.

Eligibility

A customer that requires delivery of natural gas to any residential building served through one meter and containing no more than three dwelling units.

Rate

a)	Monthly Fixed Charge	\$17.00
	Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020	\$0.59
b)	Delivery Charge	
	First 1,000 m^3 per month	14.9119 cents per m^3
	All over 1,000 m^3 per month	12.0146 cents per m^3
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020	0.1280 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)	Schedule A

Meter Readings

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

Delayed Payment Penalty

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

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 2 - Seasonal Service

Rate Availability

The entire service area of the company.

Eligibility

All customers.

Rate

	For all gas consumed from:	April 1 through October 31:	November1 through March 31:
a)	Monthly Fixed Charge	\$20.00	\$20.00
	Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020	\$0.59	\$0.59
b)	Delivery Charge		
	First 1,000 m^3 per month	17.0476 cents per m^3	21.4882 cents per m^3
	Next 24,000 m^3 per month	9.3570 cents per m^3	15.4880 cents per m^3
	All over 25,000 m^3 per month	6.7868 cents per m^3	15.2899 cents per m^3
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020	0.1280 cents per m^3	0.1280 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)		Schedule A

Meter Readings

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

Delayed Payment Penalty

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

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

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 $190.00 for firm or interruptible customers; or
A Monthly Customer Charge of $200.00 for combined (firm and interruptible) customers.

Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020	$0.59

b) A Monthly Demand Charge:

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

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 4.0367 cents per m^3,
(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 10.5118 cents per m^3 and not to be less than 7.6156 per m^3.

Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020	0.1280 cents per m^3

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

e) Overrun Gas Charges:

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

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

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or
(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

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

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

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

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

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

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

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

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

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, 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: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of EPCOR NATURAL GAS LIMITED PARTNERSHIP, can readily accept interruption and restoration of gas service with 24 hours' notice.

Rate

For all gas consumed from:		April 1 through December 31:	January1 through March 31:
a)	Monthly Fixed Charge	\$17.25	\$17.25
	Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020	\$0.59	\$0.59
b)	Delivery Charge		
	First 1,000 m^3 per month	18.5480 cents per m^3	23.6622 cents per m^3
	All over 1,000 m^3 per month	11.3804 cents per m^3	18.2847 cents per m^3
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020	0.1280 cents per m^3	0.1280 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)		Schedule A

Meter Readings

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

Delayed Payment Penalty

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

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

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

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

Rate

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

a) Monthly Fixed Charge — $190.00

Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020 — $0.59

b) A Monthly Delivery Charge:

A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 9.2650 cents per m^3 and not to be less than 5.9800 per m^3.

Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020 — 0.1280 cents per m^3

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

d) Overrun Gas Charge:

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

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

(i) the volume of gas taken in excess of the company’s maximum delivery obligation for such day, or
(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

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

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

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

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

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

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 8.2606 cents per m^3 for interruptible gas.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, 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: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

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) Fixed Monthly Charge of $71,812.87 for firm services

Rate Rider for REDA Recovery – effective for 12 months ending December 31, 2020	$0.56
Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2020	$15,413.33

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

c) 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; and
d) Competition.

Purchased Gas Transportation Charges

In addition to the Rates and Charges outlined above, IGPC is responsible for all costs, charges and fees incurred by EPCOR related to gas supplied by Enbridge Gas Inc. to EPCOR's system for IGPC. All actual charges billed to ENGLP by Enbridge Gas Inc. under former Union Gas contract ID SA008936 and SA008937, as amended or replaced from time to time, shall be billed to IGPC by EPCOR when and as billed to EPCOR by Enbridge Gas Inc.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, IGPC or its agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. 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 EPCOR, IGPC, when delivering gas to EPCOR under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to EPCOR, 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: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

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-2019-0102)	17.4859 cents per m^3
GPRA Recovery Rate	(EB-2019-0102)	(0.0856) cents per m^3
System Gas Fee	(EB-2018-0336)	0.0435 cents per m^3
Total Gas Supply Charge		17.4438 cents per m^3

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

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE BT1 – Bundled Direct Purchase Contract Rate

Availability

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

Eligibility

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

Rate

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

Note:

Ontario Point of Delivery means Dawn or Parkway on the Enbridge Gas Inc. (Union South) System as agreed to by EPCOR and EPCOR's customer or their agent.

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Transmission Service

Availability
Transmission Service charges shall be applied to all natural gas producers that sell gas into Enbridge Gas' Union South system via ENGLP's distribution system.

Eligibility
All natural gas producers, transporting gas through ENGLP's system for sale into Enbridge Gas' Union South system shall be charged the Transmission Service Rate and associated Administrative Charge. Rates and Charges will be applied only in those months that a natural gas producer delivers gas to a delivery point on ENGLP's system for sale into Enbridge Gas' Union South system.

Rate

Administrative Charge	$250/month
Transmission Service Rate	$0.95/mcf

Effective: January 1, 2020
Implementation: All bills rendered on or after January 1, 2020
EB-2018-0336

ENGLP
Schedule of Miscellaneous and Service Charges

	A Service	B Fee
1	Service Work	
2	During normal working hours	
3	Minimum charge (up to 60 minutes)	$100.00
4	Each additional hour (or part thereof)	$100.00
5	Outside normal working hours	
6	Minimum charge (up to 60 minutes)	$130.00
7	Each additional hour (or part thereof)	$105.00
8		
9	Miscellaneous Charges	
10	Returned Cheque / Payment	$48.00
11	Replies to a request for account information	$25.00
12	Bill Reprint / Statement Print Requests	$20.00
13	Consumption Summary Requests	$20.00
14	Customer Transfer / Connection Charge	$35.00
15		
16	Disconnection and Reconnection Charge	$85.00
17		
18	Inactive Account Charge	ENGLP’s cost to install service
19		
20	Late Payment Charge	1.5% / month, 19.56% / year (effective rate of 0.04896% compounded daily)
21		
22	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs
23		
24	Installation of Service Lateral	$100 (minimum). Additional if pipe length exceeds length used to set fee.

Note: Applicable taxes will be added to the above charges

10-STAFF-79

Reference: **Exhibit 10 / Tab 1 / Schedule 1/ Pg.3**

Request:

EPCOR has proposed a stretch factor of 0.3% for the Price Cap adjustment. A stretch factor of 0.3% is consistent with the stretch factor approved in the Enbridge Gas Distribution and Union Gas 2019-2024 Price Cap IR plan (EB-2017-0306/07) and the stretch factor assigned for mid-range electricity distributors (Enbridge Gas Distribution and Union Gas are now both owned by Enbridge Gas Inc.). EPCOR has further noted in its evidence that although its lacks external benchmarking to support the proposed stretch factor, EPCOR'S OM&A costs per customer have declined after the acquisition.

(a) The stretch factor denotes the cost efficiency of an individual distributor based on the results of a benchmarking study. On what basis did EPCOR determine that its distribution operation is as efficient as Enbridge Gas Distribution and Union Gas? Please provide any supporting evidence.

(b) In NRG's last IR framework, a stretch factor of 0.4% was approved (EB-2010-0018) which was further extended for another two years with the same parameters (EB-2014-0274). In EPCOR's 2018 IR proceeding (EB-2018-0235) where the IR framework was extended for the period 2017 to 2019, a stretch factor of 0.4% was approved through a settlement proposal. Please explain why EPCOR is not proposing a stretch factor of 0.4% in this application.

Response:

(a) EPCOR notes that the benchmarking analysis used for determining the efficiency of Ontario's electricity distributors is based on a total factor productivity ("TFP") analysis that takes into account various factors that result in inherent unit cost differences among distributors. There is no comparable TFP analysis for Ontario natural gas distributors that takes into account factors such as scale, customer mix and customer density and as a result, benchmarking similar to that used for electricity distributors cannot be done.

Further, since a study to benchmark its costs against other North American gas distributors is cost prohibitive for a small utility such as ENGLP, such a study was not undertaken for this Application.

In the absence of such benchmarking ENGLP has not claimed to be as efficient as Enbridge Gas and Union Gas, however, as provided in the table below, information published in the OEB's 2017 Yearbook of Natural Gas Distributors would support an assertion that ENGLP is at least as efficient as Enbridge Gas Distribution Inc. ("Enbridge Gas") and Union Gas Limited ("Union Gas"). As calculated below, Natural Resource Gas' ("NRG") 2017 'Gas Cost and Operating and Maintenance Expense' on a per customer basis was lower than both Enbridge Gas and Union Gas:

Table 10-STAFF-79-1
Comparison of Gas Cost, O&M Expense per customer

	A **Enbridge Gas**	B **Union Gas**	C **NRG**
1 Gas Cost, O&M Expense[1]	$2,498,403,042	$1,543,368,656	$8,962,634
2 Total Number of Customers[2]	2,170,215	1,474,944	8,827
3 Gas Cost, O&M Expense per customer[3]	**$1,151.22**	**$1,046.39**	**$1,015.37**

Further, as outlined in Table 4.3.1-1 and Figure 4.3.1-1 in Exhibit 4, Tab 1, Schedule 1 of the Application, ENGLP is proposing total Operating, Maintenance and Administrative Costs for the 2020 Test Year that are below NRG's 2017 costs both in terms of total dollars and on a cost per customer basis.

As outlined in Section 10.1.3 of Exhibit 10, Tab 1, Schedule 1, ENGLP noted that the Board cited the lack of benchmarking data in their finding of the mid-range factor of 0.3% as appropriate for the 'Amalco' (Enbridge Gas Inc. ("Enbridge")) in EB-2017-0306/07. Therefore, assigning the mid-point of the stretch factor values which the OEB has accepted as "normal" performance for electricity distributors would be most appropriate for ENGLP in these circumstances.

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[1] OEB 2017 Yearbook of Natural Gas Distributors published on August 23, 2018, page 6 'Income Statement', 'Gas Costs, Operating and Maintenance' expenses
[2] OEB 2017 Yearbook of Natural Gas Distributors published on August 23, 2018, page 12 'General Customer Information', 'Total Number of Customers'
[3] Calculated as 'Gas Cost, O&M Expense'/ 'Total Number of Customers'

(b) As outlined in the response to (a) above, a stretch factor consistent with the mid-point would be appropriate for the circumstances and therefore ENGLP is proposing the current mid-point stretch factor of 0.3% in this Application, rather than the mid-point stretch factor that was in place at the time of the implementation of the previous IR framework.

10-STAFF-80

Reference: **Exhibit 10 / Tab 1 / Schedule 1/ Pgs. 5-7**

Request:

EPCOR has requested an Incremental Capital Module (ICM) to address the treatment of capital investment needs that arise during the Price Cap IR term. EPCOR notes that in case of a qualifying project that requires a leave to construct application, the request for approval of the proposed adjustment to rates will be filed with the leave to construct application.

Please explain why rate adjustments related to a qualifying ICM project will be filed in a leave to construct application considering that such adjustments are usually filed in a rates application wherein the OEB considers the total capital budget in the rate year, what is funded through proposed base rates, including the cumulative and combined impact of the price cap adjustments and growth in demand. These numbers may not be known at the time of the leave to construct application. (For further information, please see OEB staff final arguments in EB-2017-0306/07, June 15, 2018.)

Response:

ENGLP agrees that the OEB staff's suggestion that the dollars for the qualifying incremental capital, the associated revenue requirement, and rate riders be determined as part of the annual Price Cap IR application rather than in the leave to construct application is reasonable. ENGLP proposes its Price Cap IR Plan be updated to reflect this change.

10-STAFF-81

Reference: **Exhibit 10 / Tab 1 / Schedule 1**

Request:

In its application, EPCOR has proposed a Price Cap IR plan that includes a number of parameters similar to other plan approved by the OEB, including productivity factor, stretch factor, Y-factors, Z-factor adjustments, ICM and an off-ramp. However, EPCOR has not proposed an earnings sharing mechanism (ESM) that has been approved for other OEB regulated gas utilities.

(a) Please explain why EPCOR has not proposed an ESM.

(b) Would EPCOR consider the ESM that was recently approved by the OEB for Enbridge Gas Distribution and Union Gas Limited in the MAADs proceeding (EB-2017-0306/07)?

Response:

(a) Unlike Enbridge Gas and Union Gas, ENGLP and its predecessor NRG have not had an ESM as a component of its incentive rate-setting framework in previous Board decisions. The earnings dead band off-ramp ENGLP has proposed in this Application aligns with that implemented by the Board for electricity distributors in Ontario – which the Board accepted as an appropriate basis for NRG's previous incentive rate-setting plan (EB-2010-0018). ENGLP notes that the OEB has not required electrical utilities to implement an ESM (except in the context of a MAAD). ENGLP continues to believe that the simplified approach originally implemented for NRG remains appropriate, since it streamlines the annual IR approach and avoids the cost and potential complexity of determining the ESM as part of an IR application.

Further, ENGLP believes that the introduction of an ESM is not consistent with the key principles of incentive rate-setting, as it does not incent the utility to maximize cost savings intended through incentive rate-making in part because rates are no longer decoupled from costs during the term of the Price Cap IR. The introduction of an ESM into the Price Cap IR also increases regulatory burden both for the utility and the OEB as a result of the ongoing management of the mechanism.

ENGLP's proposal to continue with the earnings dead band off-ramp mechanism approved by the OEB for NRG in previous applications, combined with ENGLP's proposed stretch factor, best aligns with the principles behind incentive rate-setting and provides the most benefit to ratepayers while avoiding undue regulatory burden. Under ENGLP's proposal, ratepayers are provided with up front sharing of savings through the stretch factor, as well as protection from the utility excessively overearning while still incenting the utility to continue to pursue and implement savings that will benefit the ratepayer upon rebasing in ENGLP Aylmer's next cost of service application.

(b) For the reasons outlined in ENGLP's response to (a) above, ENGLP does not believe that the ESM approved by the OEB for the Enbridge in EB-2017-0306/07 would be appropriate for ENGLP. In addition, under situations where volatility of earnings exists, as can be the case for any utility, an asymmetrical annual ESM as approved by the Board in EB-2017-0306/07 is unfairly skewed in favour of the ratepayer, particularity in regards to rates versus a MAAD application. The utility may have sufficient earnings in one year to trigger a sharing with customers and then experience earnings below the approved return in subsequent years. This deprives the utility of a reasonable opportunity to earn its approved return over the Price Cap IR Term.

ENGLP notes that the annual ESM approved by the OEB for Enbridge does not appear to align with Section 2.10 of the Board's *Filing Requirements for Natural Gas Applications* where the OEB has indicated that if a utility proposes an ESM as its mechanism to protect customers against excess earnings, it should generally be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term.