Exhibit 4 – Operating Expenses

4.0 OPERATING EXPENSES

4.1 Gas Supply and Transportation Costs

1. ENGLP has provided a detailed gas supply plan for the Aylmer gas distribution system in Exhibit 4, Tab 4, Schedule 1. The Gas Supply Plan covers the 2019-2024 periods. ENGLP notes that it does not have any gas storage costs as it purchases gas and receives gas balancing as part of its M9 contract with Enbridge. This Gas Supply Plan aligns with the Framework for the Assessment of Distributor Gas Supply Plans issued by the OEB October 25, 2018. As per direction by the OEB received December 20, 2018[1], ENGLP intends to file an update of this plan by May 1, 2019. The update will include details regarding ENGLP's plan to contract for gas supply for injection into the Southern area of the system.

2. The objective of ENGLP's Gas Supply Plan for Aylmer is to develop a right-sized portfolio of natural gas commodity and storage assets that ensure consumers receive a cost-effective, reliable and secure natural gas supply. The gas portfolio is designed to strike a balance between these guiding principles, which are consistent with the Board's legislated mandate to protect the interest of consumers with respect to prices and the reliability of gas service. The Gas Supply Plan was developed in accordance with the Framework for the Assessment of Distributor Gas Supply Plans.

3. ENGLP engaged Cornerstone Energy Services to conduct a System Integrity Study. The Gas Supply Plan is informed by the results of the study which looked at addressing system integrity and low pressure issues. The study is included with this Application in Exhibit 2, Tab 3, Schedule 1.

4. The Tables below show the 2013 to 2017 historical and 2018 to 2020 expected annual costs of gas calculations.

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[1] EB-2017-0129 Framework for the Assessment of Distributor Gas Supply Plans.

Table 4.1-1
2013 Actual Cost of Gas

	Gas Commodity	Period Covered	A m3	B $'s	C cents / m3
1	Local Production - A	Oct. 1/12 - Sept. 30/13	2,844,742	683,469	24.0257
2	Western (incl FT)	Oct. 1/12 - Sept. 30/13	3,850,100	863,263	22.4218
3	Parkway	Oct. 1/12 - Sept. 30/13	14,283,896	2,486,103	17.4049
4	Ontario Delivered	Oct. 1/12 - Sept. 30/13	2,562,965	386,023	15.0616
5	Gas Inventory Revaluation			(246,917)	
6	PGCVA	PGCVA - Fiscal 2013		156,524	
7	**Total Gas Commodity Cost**		**23,541,703**	**4,328,466**	**18.3864**
8	**Gas Transportation**				
9	Union Gas	Oct. 1/12 - Sept. 30/13		629,754	
10	Unaccounted For Gas	PGTVA - Fiscal 2013		305,181	
11	**Total Gas Transportation Cost**		**56,745,542**	**934,936**	**1.6476**
12	**Total Gas Commodity and Transportation Cost**			**5,263,401**	

Table 4.1-2
2014 Actual Cost of Gas

	Gas Commodity	Period Covered	A m3	B $'s	C cents / m3
1	Local Production - A	Oct. 1/13 - Sept. 30/14	2,568,449	627,775	24.4418
2	Western (incl FT)	Oct. 1/13 - Sept. 30/14	3,566,728	857,428	24.0396
3	Parkway	Oct. 1/13 - Sept. 30/14	15,464,524	2,973,830	19.2300
4	Ontario Delivered	Oct. 1/13 - Sept. 30/14	5,839,186	3,662,782	62.7276
5	Gas Inventory Revaluation			(1,134,100)	
6	PGCVA	PGCVA - Fiscal 2014		(1,361,159)	
7	**Total Gas Commodity Cost**		**27,438,887**	**5,626,556**	**20.5068**
8	**Gas Transportation**				
9	Union Gas	Oct. 1/13 - Sept. 30/14		633,797	
10	Unaccounted For Gas	PGTVA - Fiscal 2014		390,138	
11	**Total Gas Transportation Cost**		**60,512,168**	**1,023,936**	**1.6921**
12	**Total Gas Commodity and Transportation Cost**			**6,650,492**	

Table 4.1-3
2015 Actual Cost of Gas

	Gas Commodity	Period Covered	A m3	B $'s	C cents / m3
1	Local Production - A	Oct. 1/14 - Sept. 30/15	2,136,699	535,469	25.0606
2	Western (incl FT)	Oct. 1/14 - Sept. 30/15	3,495,011	767,872	21.9705
3	Parkway	Oct. 1/14 - Sept. 30/15	9,941,914	1,760,648	17.7093
4	Ontario Delivered	Oct. 1/14 - Sept. 30/15	11,445,070	1,827,218	15.9651
5	Gas Inventory Revaluation	Oct. 1/14 - Sept. 30/15		(14,119)	
6	PGCVA	PGCVA - Fiscal 2015		944,248	
7	**Total Gas Commodity Cost**		**27,018,693**	**5,821,335**	**21.5456**
8	**Gas Transportation**				
9	Union Gas	Oct. 1/14 - Sept. 30/15		808,385	
10	Unaccounted For Gas	PGTVA - Fiscal 2015		236,136	
11	**Total Gas Transportation Cost**		**62,706,613**	**1,044,521**	**1.6657**
12	**Total Gas Commodity and Transportation Cost**			**6,865,855**	

Table 4.1-4
2016 Actual Cost of Gas

	Gas Commodity	Period Covered	A m3	B $'s	C cents / m3
1	Local Production - A	Oct. 1/15 - Sept. 30/16	1,420,193	380,092	26.7634
2	Western (incl FT)	Oct. 1/15 - Sept. 30/16	3,782,627	553,622	14.6359
3	Parkway	Oct. 1/15 - Sept. 30/16	11,027,601	1,940,790	17.5994
4	Ontario Delivered	Oct. 1/15 - Sept. 30/16	6,208,321	473,025	7.6192
5	Gas Inventory Revaluation			54,904	
6	PGCVA	Fiscal 2016		(368,573)	
7	**Total Gas Commodity Cost**		**22,438,742**	**3,033,859**	**13.5206**
8	**Gas Transportation**				
9	Union Gas	Oct. 1/15 - Sept. 30/16		759,657	
10	Unaccounted For Gas			64,609	
11	**Total Gas Transportation Cost**		**62,801,545**	**824,267**	**1.3125**
12	**Total Gas Commodity and Transportation Cost**			**3,858,126**	

Table 4.1-5
2017 Actual Cost of Gas

	Gas Commodity	Period Covered	A m3	B $'s	C cents / m3
1	Local Production - A	Oct. 1/16 - Sept. 30/17	1,682,957	417,002	24.7780
2	Western (incl FT)	Oct. 1/16 - Sept. 30/17	405,710	58,178	14.3398
3	Parkway	Oct. 1/16 - Sept. 30/17	1,614,020	265,475	16.4481
4	Ontario Delivered	Oct. 1/16 - Sept. 30/17	(251,379)	(11,152)	4.4363
5	E2 Energy		569,018	61,600	10.8257
6	Union Gas		20,167,947	3,348,283	16.6020
7	Gas Inventory Revaluation			(140,562)	
8	PGCVA	Fiscal 2017		45,348	
9	**Total Gas Commodity Cost**		**24,188,273**	**4,044,173**	**16.7196**
10	**Gas Transportation**				
11	Union Gas	Oct. 1/16 - Sept. 30/17		969,665	
12	Unaccounted For Gas			(119,656)	
13	**Total Gas Transportation Cost**		**64,048,333**	**850,009**	**1.3271**
14	**Total Gas Commodity and Transportation Cost**			**4,894,181**	

Table 4.1-6
Forecasted Commodity and Transportation Costs in 2018

	Gas Commodity	A m3	B $	C cent / m3
1	Enbridge Gas	25,118,971	4,031,695	16.0504
2	Local Production A	1,000,000	160,504	16.0504
3	Local Production B	657,417	105,518	16.0504
5	**Total Gas Commodity Cost**	**26,776,388**	**4,297,717**	**16.0504**
6	Unaccounted For Gas	-	-	-
7	**Total Gas Transportation Cost**	**43,169,007**	**970,411**	**2.2479**
8	**Total Gas Commodity and Transportation Cost**		**5,268,128**	

Table 4.1-7
Forecasted Commodity and Transportation Costs in 2019

		A	B	C
	Gas Commodity	**m3**	**$**	**cents / m3**
1	Enbridge Gas	24,309,669	4,366,867	17.9635
2	Local Production A	1,000,000	179,635	17.9635
3	Local Production B	657,417	118,095	17.9635
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**	

Table 4.1-8
Forecasted Commodity and Transportation Costs in 2020

		A	B	C
	Gas Commodity	**m3**	**$**	**cents / m3**
1	Enbridge Gas	24,773,653	4,452,002	17.9707
2	Local Production A	1,000,000	179,707	17.9707
3	Local Production B	657,417	118,142	17.9707
4	**Total Gas Commodity Cost**	**26,431,069**	**4,749,851**	**17.9707**
5	Unaccounted For Gas	-	-	-
6	**Total Gas Transportation Cost**	**26,818,030**	**675,544**	**2.5190**
7	**Total Gas Commodity and Transportation Cost**		**5,425,395**	

5. For the 2019 cost of gas calculations, ENGLP has used the gas commodity price of 17.9635 cents per cubic meter as approved by the Board in ENGLP's latest QRAM Application.[2] The 2020 cost of gas uses the same QRAM price, updated for the system gas fee proposed in this Application of 0.0435 cents per cubic meter for a revised forecasted gas commodity cost of 17.9707 cents per cubic meter. For the Bridge and Test Years, the gas supply and demand is balanced because ENGLP has proposed a deemed unaccounted for gas of 0% as reflected in the Tables above and Enbridge provides gas balancing as an element of its M9 rate.

6. In December 2018, the Board approved the direct flow-through to IGPC of the actual costs charged to ENGLP by Enbridge Gas, and prior to 2019 Union Gas, under the M9 and Bundled T contracts for the IGPC volumes. This was approved in conjunction with moving to a fully fixed distribution rate for Rate 6 effective October 1, 2018.[3] As these costs are now a direct flow-through, the IGPC transportation volumes and costs are not included in the Tables above

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[2] EB-2018-0324, December 20, 2018.

[3] EB-2018-0235 Decision and Order, December 6, 2018, pg. 9 and Settlement Proposal, November 21, 2018, pg. 18.

commencing the effective date of this change. This is the reason that transportation volumes and costs decrease from 2018 to 2019.

7. In NRG's last rate case regarding the issue of NRG acquiring gas from NRG Corp. for system integrity purposes, the Board stated "*The Board will allow NRG to recover from ratepayers a maximum annual quantity of 1.0 million cubic meters of natural gas at the rate of 8.486 per mcf. Any additional quantities beyond 1.0 million cubic meters that are purchased from NRG Corp. would only be eligible for recovery from ratepayers at current market rates that would be determined quarterly as per the methodology outlined in the Board's Decision of December 6, 2010.*"[4]. As part of its purchase of system assets from NRG (EB-2016-0351) ENGLP executed a Gas Purchase Agreement[5] that included the right of NRG Corp. to sell up to 1.0 million mcf of gas to ENGLP at that price. The Gas Purchase Agreement expires on September 20, 2020.

8. As further detailed in ENGLP's System Integrity Study (Exhibit 2, Tab 3, Schedule 2), the potential for system pressure issues remain. However, as part of its Utility System Plan (Exhibit 2, Tab 3, Schedule 1) and Gas Supply Plan (Exhibit 4, Tab 4, Schedule 1), ENGLP is proposing a cost effective solution that is expected to eliminate the requirement to purchase gas at other than market rates. This plan includes the construction of an additional gas injection site (the Lakeview project) and contracting with local gas suppliers to supply gas to that point. ENGLP expects this solution to be in place in advance of the Gas Purchase Agreement expiring on September 20, 2020. As a result, ENGLP is proposing that it continue to recover from ratepayers $8.486 per mcf for the first 1.0 million m^3 purchased from On-Energy Corp. until September 20, 2020.

9. In its Decision and Order for EB-2010-0018 dated December 6, 2010 the Board determined that NRG would use Union Gas' Ontario Landed Reference Price in the QRAM process to adjust the contract price with NRG Corp. for gas purchased under the Gas Purchase Agreement in excess of the system integrity volume, which was determined to be 1.0 million cubic meters on an annual basis. Subsequent to this decision and as explained in Union Gas' EB-2016-0334 QRAM application, Union ceased calculating an Ontario Landed Reference Price, replacing it with the Dawn reference price effective January 1, 2017. In the absence of the Ontario Landed Reference Price, ENGLP and previously its predecessor NRG, has used Union Gas' Dawn reference price as the contract price for these volumes in its QRAM. The Board approved the use of the Dawn reference price for determining the cost of gas purchases in excess

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[4] EB-2010-0018, Decision and Order – Phase 2, May 17, 2012 pg. 9.

[5] During 2018, NRG Corp sold its interest in the wells providing gas to ENGLP to On-Energy Corp. This sale included the Gas Purchase Agreement.

of 1.0 million cubic meters from NRG Corp. on an interim basis in EB-2016-0341 and indicated that this matter should be brought forward in NRG's 2017-2021 rates application. Since January 1, 2017 ENGLP's QRAM pricing has been approved on an interim basis pending the approval of the use of the Dawn reference price in the next cost of service application.

10. ENGLP requests approval to use the Dawn reference price to determine the cost of gas purchases in excess of 1.0 million cubic meters from NRG Corp. (and its successor On-Energy Corp.) for the period January 1, 2017 until September 30, 2020 (the end of the term of the current Gas Purchase Agreement) and requests that the QRAM pricing that became interim as of January 1, 2017 as a result of the replacement reference price be made final as a part of this Application.

4.2 Lost and Unaccounted for Gas

11. This section details ENGLP's proposed unaccounted for gas ("UFG") rate for its Aylmer natural gas distribution system. UFG represents the difference in the volume of gas received into the system from all sources, in this case from Enbridge Gas and local production from wells, and the total volume of gas accounted for through measured deliveries to customers or for ENGLP's use.

12. There are typically two types of UFG, operational, and accounting based. Operational UFG includes leakage, variations in pressure and/or temperature (both causing changes in the distribution system's line pack), fugitive emissions, and meter inaccuracies or other unidentified reasons. Accounting UFG can result from data entry errors, misreporting of meter reads, timing of meter readings to billing, measurements being made at different times and at different points on the system or other unidentified reasons.

13. Historically, the approved UFG rate was 0% and the actual UFG reported by NRG was often close to zero. The calculated UFG as reported by NRG for the last five historical years is:

Table 4.2-1
2013 to 2017 Actual Unaccounted For Gas Calculation
(m^3)

		A **2013 A**	B **2014 A**	C **2015 A**	D **2016 A**	E **2017 A**
1	Gas Consumption	24,288,293	28,097,184	28,231,239	23,398,631	25,110,034
2	Gas Deliveries into the system	25,285,340	28,978,088	28,789,077	24,049,657	25,641,042
3	Gas Gain / (Loss)	(997,047)	(880,904)	(557,838)	(651,026)	(531,008)
4	**Variance (%)**	**-4.1%**	**-3.1%**	**-2.0%**	**-2.8%**	**-2.1%**

14. Consistent with prior approvals, ENGLP proposes a deemed UFG of 0% for use in this Application. As described in Section 9.3.1 of Exhibit 9, Tab 1, Schedule 1, ENGLP proposes to establish a variance account (Unaccounted for Gas 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.

4.3 Operating, Maintenance and Administrative Costs

4.3.1 Operating, Maintenance, and Administrative Costs Overview (OM&A)

15. ENGLP's 2019 Bridge Year and 2020 Test Year and previous years' OM&A costs are shown in Table 4.3.1-1 below.

Table 4.3.1-1
Summary of OM&A 2011-2020
($)

		A	B	C	D	E	F	G	H	I	J	K
	Expense Category	**Board Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A[1]**	**2018 F[2]**	**2019 Bridge Year**	**2020 Test Year**
1	WFP and Employee Compensation	1,219,057	995,870	1,343,213	1,335,700	1,376,847	1,441,024	1,561,365	1,336,675	1,217,748	1,255,343	1,432,123
2	Operating Support Costs[3,4]	1,410,151	1,605,933	1,601,662	1,744,912	2,291,503	1,694,557	1,924,583	2,142,674	2,014,078	1,113,508	1,026,274
3	Shared Services and Corporate Cost Allocation	-	-	-	-	-	-	-	-	883,592	868,724	892,722
4	Low Income Program	-	-	-	-	-	-	-	-	6,582	6,582	7,983
5	**Total[5]**	**2,629,208**	**2,601,803**	**2,944,875**	**3,080,612**	**3,668,350**	**3,135,581**	**3,485,948**	**3,479,349**	**4,122,001**	**3,244,157**	**3,359,102**

[1] 2017 Actual based on a fiscal period of October 1, 2016 to September 30, 2017.

[2] 2018. 2019 and 2020 Forecast based on a fiscal period of January 1 to December 31.

[3] One Time costs are reflected within Operating Support Costs under regulatory.

[4] Non-Affiliate costs are reflected within Operating Support Costs.

[5] Excluded from the total OM&A costs for 2018, 2019 and 2020 are the amounts associated with the system gas fee as these amounts are removed from the OM&A costs for the purposes of determining the distribution revenue requirement. The costs removed are $11,012, $11,196 and $11,501 respectively.

16. Overall, the main business environment changes affecting ENGLP Aylmer's operations since its last approval (2011) is the change in ownership from NRG to ENGLP (November 2017), increase in customer count of over 34% (from approximately 7,155 in 2011 to a forecast of 9,538 for 2020),an increased focus on cyber security, and increased regulatory work related to a number of regulatory initiatives, and increased administration and system flexibility needed to support billing and customer reporting requirements.

17. On an overall basis, ENGLP's OM&A levels have been on a slight increasing trend since the previous owner NRG's last OEB Approved amount (EB-2010-0018). ENGLP cannot speak definitively about the costs from 2011 to 2017 as ENGLP was provided limited documentation for results prior to the acquisition. For the 2018 Forecast, 2019 Bridge Year and 2020 Test Year, the main drivers for cost decreases and increases are provided below.

18. The decrease in OM&A costs for ENGLP's 2018 Forecast to the 2019 Bridge Year is primarily due to the following:

- Lower Operating Support costs primarily due to higher One Time Costs in 2018 for NRG and ENGLP Applications. The details are further discussed in Section 4.3.3.5.

19. This decrease from 2018 to 2019 is partially offset due to higher employee compensation due to the following:

- Market compensation adjustment for ENGLP employees' wages to reflect market-competitive wage rates (Employee Compensation Review). EPCOR's Human Resources (HR) department conducted a review of ENGLP employees' wages to local wages and determined that ENGLP employees' wages were on average approximately 19.9% below local rates. In addition, ENGLP contracted with Willis Towers Watson (WTW), an independent third party consultant to review EPCOR HR's approach to assess market competiveness rates for ENGLP's Aylmer's wage rates. WTW confirmed EPCOR HR's approach and determined their findings were reasonable (see Exhibit 4, Tab 4, Schedule 2) ENGLP has increased ENGLP employees' such that ENGLP employees' wages will reflect market competitive wage rates by the 2020 Test Year.

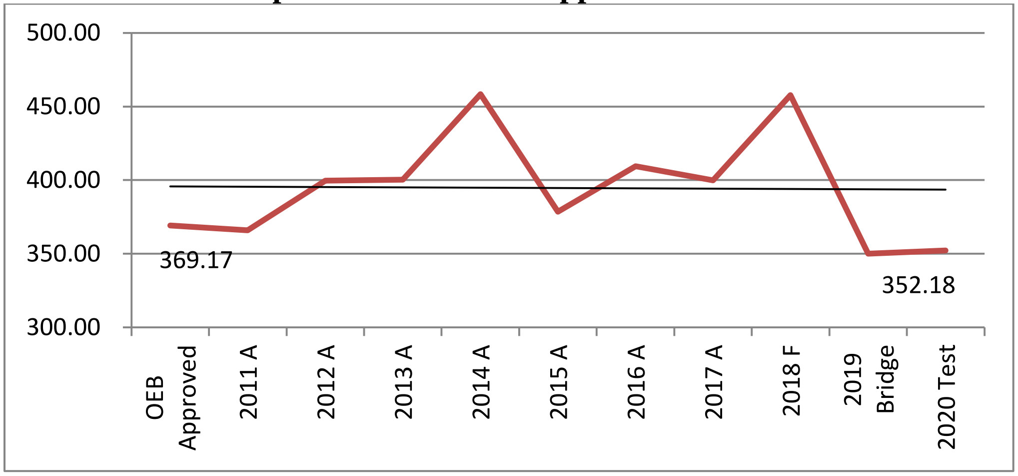
- Higher benefit costs due to the increase in employee salaries from the market adjustments, as described above.
- Full year impact of salary costs from filling vacancies in 2018.
- These increases are further discussed in detail in Section 4.3.3.1.

20. The increase in ENGLP's 2019 Bridge Year to 2020 Test Year is primarily due to the Market compensation adjustment as discussed above.

21. When ENGLP compares its 2020 Test Year OM&A costs to NRG's last OEB approval and 2011 to 2017 Actual costs, ENGLP notes the following two observations:

1) ENGLP's 2020 Test Year costs are lower than NRG's Actual costs over the five year period from 2013 to 2017.
2) ENGLP's 2020 Test Year OM&A cost per customer is lower than the last OEB approved and NRG's 2011 to 2017 Actual OM&A cost per customer amount. Further over this same time frame, ENGLP's OM&A cost per customer is on a downward trajectory. The following Figure shows this graphically below.

Figure 4.3.1-1
OM&A cost per customer OEB Approved to 2020 Test Year



22. As reflected in the Figure above, on an OM&A per customer basis, ENGLP customers are paying less than what was last approved by the OEB (i.e., $352.18 versus $369.17). ENGLP considers that its 2020 Test Year OM&A costs strikes the balance between its requirement to provide utility service and rates that are reasonable and prudent and in the public interest and as such, its customers are the primary beneficiaries. Over the course of the term, ENGLP will

continually monitor and assess its OM&A costs and the delivery of shared services to ENGLP. As opportunities arise for EPCOR to increase its Ontario operations, EPCOR and ENGLP will look for possible cost efficiency opportunities from economies of scale with respect to sharing of resources (i.e., similar to Southern Bruce as described in Section 4.3.3.1) and the delivery of shared services across the increased operational sites within Ontario. Such opportunities, should they arise, will benefit ENGLP Aylmer customers through lower OM&A costs in the future.

23. The following Table summarizes the inflation rates that ENGLP has applied to 2018 Forecast to 2019 Bridge Year and 2019 Bridge Year to 2020 Test Year.

Table 4.3.1-2
Summary of Inflation Rates 2019-2020

	Expense Category	A **2019** **Bridge Year**	B **2020** **Test Year**
1	Management Salary	0.0%	2.8%
2	Non-Management Salary	0.0%	2.8%
3	Contractors	2.3%	2.7%
4	Materials	2.4%	2.2%
5	Other	2.3%	2.1%

24. For Management and Non-Management salary escalation rates for 2019 and 2020, EUI's HR department reviewed 2019 salary escalation projections across Canada and Ontario which ranged from 2.5% to 2.8%[6] and also noted that Ontario's unemployment rate was the second lowest across Canada at 5.4%[7]. ENGLP Aylmer's Management salary escalation forecasts reflect the upper end of the range at 2.8% with the view that Ontario's low unemployment rate may put upward pressure on labour in Ontario for 2019 and continue into 2020. ENGLP notes that for 2019, it did not apply the 2.8% salary escalation rate as it was factored into the salary adjustments for employees related to the Employee Compensation review as described above and in more detail in Section 4.3.3.1.

25. For Contractor, Materials and Other cost escalation rates for 2019 and 2020, ENGLP used the same escalators that EPCOR Energy Alberta GP Inc. and EPCOR Distribution and Transmission Inc., subsidiaries of EPCOR Utilities, used for its 2018-2020 Regulated Rate Tariff

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[6] https://www.benefitscanada.com/news/salary-increases-to-rise-slightly-in-2019-survey-119372
https://www.conferenceboard.ca/press/newsrelease/2018/10/31/slightly-higher-salary-increases-expected-for-canadian-workers-in-2019
https://www.newswire.ca/news-releases/morneau-shepell-survey-shows-salaries-expected-to-increase-by-26-per-cent-in-2019-690803551.html

[7] https://www150.statcan.gc.ca/n1/daily-quotidien/190104/dq190104a-eng.htm

Application and 2018-2019 Transmission Tariff Application. The escalators were developed by Robert Fairholm Economic Consulting Inc. an independent third party. A copy of the reports from EEA's and EDTI's Applications has been provided as Exhibit 4, Tab 4, Schedules 3 and 4, respectively. ENGLP considered it prudent to use these escalators rather than develop new escalators for ENGLP Aylmer as the impact of a change in the escalation rates on these costs is immaterial (i.e., 0.1% change for contactors, materials and other is $294, $98 and $387 and $210, $97 and $392 respectively for 2019 and 2020). In addition, ENGLP notes that for other costs, in some instances ENGLP adjusted the costs to reflect known changes.

26. The following sections provide additional details of each OM&A expense category.

4.3.2 Summary and Cost Driver Tables

27. The following Table summarizes the recoverable OM&A expenses that ENGLP is requesting for approval for the 2020 Test Year.

Table 4.3.2-1
2020 Summary of Recoverable OM&A Expenses
($)

	OM&A Expense	A Section Reference	B 2020 Test Year
1	Employee Salaries	4.3.3.1	1,341,240
2	Benefits	4.3.3.1	362,030
3	Incentive Plan (STIP)	4.3.3.1	77,900
4	Salary Transfer (out)	4.3.3.1	(349,047)
5	Insurance	4.3.3.2	86,211
6	Utilities	4.3.3.2	17,443
7	Advertising	4.3.3.2	34,240
8	Telephone	4.3.3.2	36,000
9	Office & Postage	4.3.3.2	127,394
10	Repair & Maintenance	4.3.3.2	198,122
11	Automotive	4.3.3.2	45,748
12	Dues & Fees	4.3.3.2	31,185
13	Regulatory	4.3.3.2	211,852
14	Bad Debts	4.3.3.2	34,200
15	Bank Charges	4.3.3.2	6,019
16	Travel & Ent.	4.3.3.2	15,145
17	Legal	4.3.3.2	34,468
18	Audit	4.3.3.2	31,334
19	Consulting Fees	4.3.3.2	116,913
20	Affiliate Services	4.3.3.3	453,505
21	Corporate Shared Services	4.3.3.3	439,217
22	Low Income Programs	4.3.3.6	7,983
23	**Total**		**3,359,102**

28. Additional details of each line item in the table above are provided in its respective referenced section as noted in column A.

29. The Tables below provides a list of the cost drivers that affected the year over year OM&A spending since the last OEB Approved amount (2011). In some cases cost drivers are common or recurring and have impacted expenditures in multiple years.

30. Table 4.3.2-2 provides the historical year over year changes for the 2011 to 2017 period. ENGLP is unable to provide meaningful explanations of the year over year changes for this timeframe as NRG was the owner. Further, ENGLP's 2018 Forecast, 2019 Bridge Year and 2020 Test Year numbers are based on a bottom up budget and as such, comparisons to historical actuals (2011 to 2017) would have limited value in assessing the 2020 Test Year costs.

Table 4.3.2-2
Cost Driver Table 2011-2017
($)

	OM&A	A **2011 Actual**	B **2012 Actual**	C **2013 Actual**	D **2014 Actual**	E **2015 Actual**	F **2016 Actual**	G **2017 Actual**
1	**Opening Balance**	**2,629,208**	**2,601,803**	**2,944,875**	**3,080,612**	**3,668,350**	**3,135,581**	**3,485,948**
2	Change in Salary and Wages	(176,664)	348,094	(24,885)	59,740	55,383	104,005	(207,484)
3	Change in benefits	(36,121)	30,570	(2,636)	(5,293)	4,658	18,661	(17,205)
4	Change in salary transfers	(10,402)	(31,321)	20,008	(13,300)	4,136	(2,325)	-
5	Change in Insurance	17,721	8,836	(11,659)	(109,499)	9,794	5,236	(10,473)
6	Change in Utilities	(6,862)	(1,367)	1,211	(1,218)	940	1,135	(2,375)
7	Change in Advertising	(12,594)	21,430	(9,093)	(8,295)	6,484	11,097	(30,447)
8	Change in Telephone	(25,594)	(9,548)	(1,735)	(1,443)	1,605	1,456	(2,304)
9	Change in Office & Postage	(28,545)	1,732	6,485	7,885	14,913	2,602	(14,570)
10	Change in Repair & Maintenance	(82,987)	15,485	4,808	(7,377)	30,355	33,442	(113,576)
11	Change in Automotive	(17,537)	15,346	(7,431)	19,712	(15,574)	6,484	(14,372)
12	Change in Dues & Fees	(12,287)	32,558	(14,064)	(13,657)	580	1,045	(17,873)
13	Decrease in Mapping Expense	(919)	-	-	-	-	-	-
14	Change in Regulatory	167,576	(32,097)	154,427	636,067	(811,617)	(11,856)	(150,490)
15	Change in Bad Debts	(27,600)	(32,200)	29,489	2,345	5,132	2,834	(15,406)
16	Change in Interest - Security Deposits	(4,553)	899	(1,679)	1,199	(7,129)	6,831	(1,135)
17	Change in Bank Charges	31,091	(22,638)	(7,438)	1,555	(5,411)	3,592	15,919
18	Change in Collection Expense	(11,992)	344	(1,335)	4,391	(3,466)	858	(3,953)
19	Change in Travel & Entertainment	(822)	472	(593)	2,939	2,064	790	(5,475)
20	Change in Legal	(29,267)	(22,861)	12,161	1,480	189,394	89,661	690,130
21	Change in Audit	(4,025)	10,797	(8,772)	1,750	(1,750)	15,000	(9,000)
22	Change in Consulting Fees	(26,885)	8,541	(1,532)	8,757	(13,260)	59,819	(96,510)
23	Increase in Management Fees	221,863	-	-	-	-	-	-
24	Correction on CCA issue	75,000	-	-	-	-	-	-
25	Decrease in Miscellaneous	(25,000)	-	-	-	-	-	-
26	**Closing Balance**	**2,601,803**	**2,944,875**	**3,080,612**	**3,668,350**	**3,135,581**	**3,485,948**	**3,479,349**

31. Table 4.3.2-3 provides the year over year changes for ENGLP's 2018 Forecast, 2019 Bridge Year and 2020 Test Year. Year over year variance analysis is provided below for items with a variance threshold greater than $50,000, in line with the Board's requirements.

Table 4.3.2-3
Cost Driver Table 2018 to 2020
($)

	OM&A	A 2018 Forecast	B 2019 Bridge Year	C 2020 Test Year
1	**Opening Balance**	**3,479,349**	**4,122,001**	**3,244,156**
2	Salary Escalation			33,861
3	Net decrease in Labour (executive and accounting employees not transferred to EPCOR)	(176,076)		
4	Increase in Benefits with transition to EPCOR benefits program and inclusion of Short term Incentive (STIP)	119,799		
5	Change in Labour due to Employee Compensation Review		102,743	101,160
6	Change in Benefits due to Employee Compensation Review		54,302	36,361
7	Change in STIP due to Employee Compensation Review		18,461	5,483
8	Full year impact from filling vacancies in 2018		73,485	
9	Decrease in Salaries and Benefits for System Gas Fee			(84)
10	Increase in Salary Transfers	(62,650)	(160,119)	
11	Increase in Capital Overhead		(51,278)	
12	Reduction in Insurance cost with transfer to EPCOR	(89,594)	3,188	3,316
13	Increase in Utilities	953	6,095	870
14	Change in Advertising	(627)	26,481	(26,696)
15	Change in Telephone	14,050	(14,046)	8,400
16	Change in Office and Postage	38,215	(30,571)	1,320
17	Change in Repair and Maintenance	79,627	14,112	(1,821)
18	Change in Automotive	(6,701)	(6,120)	941
19	Increase in Due and Fees	11,733	182	1,263
20	Change in Regulatory (includes one-time costs)	824,327	(680,417)	4,932
21	Increase Bad Debts	5,892	3,714	
22	Removal of Interest - Security Deposits	(865)		
23	Change in Bank Charges	(19,790)	(8,626)	16
24	Decrease in Collection Expense	(4,847)		
25	Change in Travel and Entertainment	9,968	(706)	2,358
26	Change in Legal	(954,674)	3,303	709
27	Change in Audit	33,750	(27,060)	644
28	Change in Consulting Fees	385,955	(189,047)	(83,485)
29	Elimination of in Management Fees with transition to EPCOR	(457,020)		
30	Miscellaneous	1,053	(1,053)	
31	Addition of EPCOR Affiliate Costs upon change in ownership	477,608		12,353
32	Decrease in Affiliate Costs		(36,456)	
33	Addition of EPCOR Corporate Shared Services upon change in ownership	405,984	21,588	11,645
34	Low Income Program	6,582		1,401
35	**Closing Balance**	**4,122,001**	**3,244,156**	**3,359,102**

32. The following variance analysis provides the main cost drivers for the 2018 Forecast (changes from 2017 Actual to 2018 Forecast). ENGLP notes that it has limited to no information on the details that make up the 2017 Actuals as NRG was the owner. As such, ENGLP has provided likely cost driver information where possible, based on its limited understanding of the 2018 Forecast compared to the 2017 Actuals:

- Decrease in labour (row 3) reflecting the reduction of employee FTE count as further described in Section 4.3.3.1.
- Increase in employee benefits (row 4) due to a change in benefits from NRG to ENGLP and the inclusion of a Group RRSP, employee savings plan and short term incentive.

- The reduction in insurance costs (row 12) is related to costs savings achieved upon transfer of the assets to ENGLP as further described in Section 4.3.3.2.
- Increase in regulatory costs (row 20) reflecting one-time costs comprised of regulatory expenses for cost of service applications and proceeding EB-2018-0235 as further described in Section 4.3.3.5.
- Elimination of the Management Fees (row 29) from Ayerswood Development Corp. ("ADC") and offsetting increases in Affiliate (row 31) and Corporate Shared Services (row 33) as ENGLP receives services on a shared service model from affiliate companies and its parent EUI for Corporate Services costs as further described in Section 4.3.3.3.
- Increase in Consulting Fees (row 28) primarily due to addition of the Transitional Services Agreement ("TSA") costs paid to ADC for the transfer of and use of the ADC's rate models and supporting information for NRG's 2016 cost of service filing as further described in Section 4.3.3.2.

33. The following variance analysis provides the main cost drivers for the 2019 Bridge Year (changes from 2018 Forecast to 2019 Bridge Year):

- Increase labour and benefits (rows 5, 6 and 7) reflecting the market adjustment of employee wages due to the Employee Compensation review as further described in Section 4.3.3.1.
- Increase in labour (row 8) reflects the full year impact in 2019 from filling of vacancies in 2018.
- Increase in salary transfers (row 10) reflects 0.5 FTE supporting ENGLP's Southern Bruce operations, resulting in a decrease in employee costs to ENGLP's Aylmer operations as further described in Section 4.3.3.1.
- Increase in capital overhead (row 11) reflects greater employee involvement in capital projects and not a change to the capital overhead. As a subsidiary EPCOR, ENGLP adheres to EPCOR's Capitalization Overhead policy as further described in Section 2.4.1.
- Decrease in regulatory costs (row 20) as a result of lower one-time costs for this Application in 2019 compared to 2018 and no costs related to proceeding EB-2018-0235 in 2019.
- Decrease in consulting fees (row 28) primarily due to the TSA costs as the TSA fees were $0.30 million in 2018 and $0.09 million in 2019.

34. The following variance analysis provides the main cost drivers for the 2020 Test Year (changes from 2019 Bridge Year to 2020 Test Year):

- Increase labour and benefits (rows 5,6 and 7) reflecting the market adjustment of employee wages due to the Employee Compensation review as further described in Section 4.3.3.1.
- Decrease in consulting fees (row 28) as the term of the Transitional Services Agreement (“TSA”) ends in 2019 and therefore no costs related to this agreement will be incurred in 2020.

4.3.3 Program Delivery Costs with Variance Analysis

4.3.3.1 Workforce Planning and Employee Compensation

35. Workforce Planning and Employee Compensation sets out ENGLP’s workforce planning and compensation strategy and structure for its Aylmer business unit.

Workforce Planning:

36. To ENGLP’s knowledge, NRG did not have a formalized workforce plan on which to comment or compare outcomes.

37. Since ENGLP acquired the utility’s assets from NRG in November 2017, ENGLP has reviewed its operational and business goals against its workforce requirements and financial strength and the impact on customers. ENGLP’s workforce plan is designed to ensure the size, experience, knowledge, and skills of its workforce can achieve its objectives to provide safe, reliable, secure, cost–efficient and environmentally responsible operation of ENGLP’s Aylmer operations distribution system.

38. ENGLP’s workforce plan is built on two key components that go hand in hand: i) building and maintaining a skilled workforce and ii) offering market-competitive employee compensation.

39. To ensure ENGLP can achieve its objectives, employees must possess the appropriate skills (i.e., education) and training, both technical and non-technical to complete the work and

have access to any necessary ongoing training and development required to be successful. As ENGLP is now part of EPCOR, its employees are leveraging EPCOR's program offerings to meet some of their training and developmental needs. In addition, ENGLP recognizes the importance of cross-training its employees as a cornerstone for running an efficient utility business. As a result, ENGLP focuses on cross-training its employees to fill in service gaps when needed. Cross-training of employees promotes teamwork, increases employee morale and provides improved customer service by allowing one team member to step in and resolve issues when another employee is either away or unavailable.

40. Lastly and equally important is to ensure ENGLP's employees are receiving total compensation that is competitive. Paying too much could harm the ENGLP's overall competitiveness. Paying too little could make it difficult to recruit new employees and create employee dissatisfaction, which with a relatively small team in ENGLP Aylmer could have a significant impact on its operations and its customers. ENGLP's compensation strategy and structure are based on EPCOR's (ENGLP's parent) compensation philosophy, which is determined by the Human Resources and Compensation Committee of the EPCOR Board. EPCOR's compensation philosophy targets the "mid-market" or 50th percentile of a defined peer group for total employee compensation. EPCOR's defined peer group is comprised of Energy, Utility and Pipeline organizations of similar size to EPCOR. These organizations may be autonomous companies, subsidiaries and/or divisions or joint ventures.

41. ENGLP did not believe that establishing compensation with EPCOR's defined peer group would have been reflective of wages and salaries in the Aylmer local market. In addition, in ENGLP's case, sufficient market data is not readily available to properly determine the 50th percentile (i.e., there is one large employer and a few smaller employers providing natural gas distribution in the local region and, given the small number that would participate in large third party surveys, there would not be sufficient responses to provide median market data). Therefore, ENGLP reviewed local collective agreements to determine the average local rate for similar positions in order to determine competitiveness. This approach ensures that ENGLP neither pays its employees too much nor too little in the local area.

42. ENGLP's workforce plan is designed to have a skilled and engaged workforce that is proud to work for the utility and the community it serves which ensures ENGLP can meet its objectives for its Aylmer business unit.

43. ENGLP’s 2018 Forecast, 2019 Bridge Year and 2020 Test Year and previous years’ compensation costs are shown in Table 4.3.3.1-1 below.

Table 4.3.3.1-1
Employee Compensation 2011-2020
($)

		A	B	C	D	E	F	G	H	I	J	K
	Expense Category	**OEB Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2018 F**	**2019 Bridge Year**	**2020 Test Year**
1	Management FTE		5	6	6	5.5	6	6	6	4.5	4.5	4.5
2	Non-Management FTE		14.3	15.5	15.3	16.1	15.4	15	15	13	13	13
3	**Total FTE**	**21***	**19.3**	**21.5**	**21.3**	**21.6**	**21.4**	**21**	**21**	**17.5**	**17.5**	**17.5**
4	Total Salaries[1]	1,101,919	925,255	1,273,349	1,248,464	1,308,204	1,363,587	1,467,592	1,260,108	1,030,075	1,206,304	1,341,240
5	Benefits	158,934	122,813	153,383	150,747	145,454	150,112	168,773	151,568	271,367	325,669	362,030
6	Incentive Plan (STIP)	-	-	-	-	-	-	-	-	53,956	72,417	77,900
7	Salary Transfers (Out)	(41,796)	(52,198)	(83,519)	(63,511)	(76,811)	(72,675)	(75,000)	(75,000)	(137,650)	(349,047)	(349,047)
8	**Total**	1,219,057	995,870	1,343,213	1,335,700	1,376,847	1,441,024	1,561,365	1,336,675	1,217,748	1,255,343	1,432,123
9	**Variance**			347,343	(7,513)	41,147	64,177	120,341	(224,690)	(118,927)	37,594	176,780

* ENGLP relied on NRG’s 2010 Application (EB-2010-0018) to determine OEB approved FTE. The information included in that application did not provide a Management and Non-management FTE split.

[1] Salary costs includes a reduction for the portion of Salaries and Benefits that constitute the System Gas fee.

Employees:

44. ENGLP has two broad categories of FTEs for its Aylmer operations: management and non-management. ENGLP's management group consists of 4.5 FTEs (0.75 FTE General Manager, 1.0 FTE Senior Advisor, 1.0 FTE Utility Services Manager, 1.0 FTE Coordinator Sales & Emergency Field Supervisor and 0.75 FTE Administrative & Field Supervisor) and ENGLP's non-management group consists of 13.0 FTEs that are further divided into two groups: Field and Office employees. There are seven field FTEs consisting of 4.0 Field Technicians FTEs, 1.0 Utility Service Technician FTE, 1.0 Construction Lead FTE and 1.0 Field Construction Technician FTE and six Office FTEs employees consisting of 1.0 Billing Clerk FTE, 1.0 Collections Clerk FTE, 1.0 Administrative Clerk & Sales Support FTE, 1.0 Dispatch FTE, 1.0 Billing & Dispatch Clerk FTE and 1.0 Admin Clerk FTE.

45. For the 2020 Test Year, ENGLP is proposing to maintain its current complement of 17.5 FTEs (4.5 Management and 13 Non-Management). ENGLP notes that since EPCOR's acquisition of the distribution system assets from NRG in November 2017, there has been a 3.5 FTE reduction related to the following:

- Elimination of 3.0 Executive Management FTEs and 1.0 Accounting FTE. Prior to the acquisition of assets by ENGLP, ENGLP understands that NRG employed three FTEs to provide executive oversight and one FTE for accounting purposes. As ENGLP employs a shared service model that will provide ENGLP's Aylmer business unit with these types of services along with additional services, these 3.0 FTEs are no longer required. Additional detail on EPCOR's shared service model and types of services are provided in Section 4.3.3.3.
- A 0.5 FTE reduction by realizing economies of scale with existing EPCOR Ontario operations by way of sharing resources (i.e., General Manager and Administrative & Field Supervisor) to minimize costs.
- A 1.0 FTE addition for the Senior Advisor position. The Senior Advisor is accountable for identifying 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, this position is responsible for Direct Purchase contract management including ensuring accurate and complete forecasting and contract adherence.

Employee Compensation:

46. ENGLP's structure for compensating both management and non-management employees has three components:

- Base compensation (annual salary)
- Employer Paid benefits; and
- Short term incentive (STI) Program

47. "Base compensation" refers to the annual salary for salaried employees or the hourly wage rate times the standard number of hours worked (2,080 for 8.0 hour per day employees). It does not include any employer-paid benefits such as health or retirement plan premiums. Time-related benefits such as vacation allowance and short-term disability are included in the annual base salary.

48. As described above, an average of local industry rates for similar positions is used to determine a competitive rate of pay to ensure ENGLP meets its compensation objectives. Given the lack of robust market data for the region and to ensure an appropriate comparison of wages reflective of the region, the approach was slightly modified but still aligned with EPCOR's compensation strategy. EPCOR's Human Resources department (HR) conducted a review of ENGLP employees' wages to local wages. ENGLP's wage rates were compared to the local collective agreements from Enbridge, Union Gas, Kitchener Utilities, Kingston Utilities and Erie Thames Powerlines Corporation. ENGLP Management, based on their knowledge of these other employers, worked in collaboration with HR to align ENGLP's employee positions with similar position classifications from these collective agreements to determine if ENGLP's wage rates were market competitive. HR determined that ENGLP wage rates for those positions that could be benchmarked were on average approximately 19.9% below the local rates (i.e. market).

49. Based on the above findings (i.e., significant wage gap between ENGLP's Aylmer employees salary compensation compared to the market) ENGLP determined that is was prudent to move its employees' salary compensation at its Aylmer business unit to the market salary compensation by the 2020 Test Year. HR also developed three Office Administrative types (Admin 1, 2 and 3) and four Field types (Senior Field Technician, Field Technician, Construction Lead and Field Tech Support) to recognize that office and field positions have different qualification requirements and accountabilities.

50. ENGLP is proposing the following wage rate adjustments in the 2019 Bridge Year and 2020 Test Year to bring ENGLP's employees salary compensation of its Aylmer business unit employees in line with the local market for similar positions. The following Table includes the proposed wage rate adjustments.

Table 4.3.3.1-2
Proposed Wage Rate Adjustments by Classification
($)

		A	B	C	D	E	F
	Classification	**Current ENGLP 2018**	**Proposed ENGLP 2019 Bridge Year**	**Proposed ENGLP 2020 Test Year**	**Total Increase From 2018 to 2019**	**Total Increase From 2019 to 2020**	**Total Increase**
1	Management	404,886	465,793	491,178	60,907	25,385	86,292
2	Non-Management	-	-	-	-	-	-
3	Office	223,929	318,984	384,434	95,055	65,450	160,505
4	Field	379,984	424,538	468,724	44,555	44,185	88,740
5	Remove Salary Escalation					(33,861)	(33,861)
6	Vacancy Adjustment				(73,485)		(73,485)
7	**Total**[1]	**1,008,799**	**1,209,316**	**1,344,336**	**127,032**	**101,160**	**228,191**

[1] Excludes Non-Management overtime and reduction for the System Gas Fee.

51. As reflected in the Table above, the impact of the Employee Compensation Review to adjust employee wages/salaries to a competitive rate in line with the local market is $127,032 and $101,160 for 2019 and 2020, respectively.

52. Further, ENGLP contracted with Willis Towers Watson (WTW), an independent third party consultant to review EPCOR HR's approach to assess market competiveness rates for ENGLP's Aylmer's wage rates. WTW confirmed EPCOR HR's approach and determined their findings were reasonable. WTW's Memo is attached as Exhibit 4, Tab 4, Schedule 2.

Benefits:

53. ENGLP offers all of its employees a fair benefits package. The current benefits package includes: basic life and disability benefits and extended health care and dental coverage. Details on the items included in benefits are not included in EB-2010-0018 to inform what employee benefit programs were included in costs which made up the last OEB-approved revenue requirement. ENGLP understands the benefits package for NRG employees just prior to the transition to ENGLP included basic life and disability benefits and extended health care and dental coverage. However, ENGLP's knowledge of this coverage is limited and information related to benefits provided prior to this time was not provided by NRG. The cost of employee benefits has increased throughout the 2018 to 2020 period mainly due to the impact of the

increase in employee salaries from the market adjustments (as described above) on benefits such as the Group RRSP and employee savings plan (matches employees' contributions up to 5%). ENGLP notes that there is no employee pension plan. This results in an increase in employee costs to ENGLP as reflected in row 5 of Table 4.3.3.1-1.

Short Term Incentive Program (STI):

54. EPCOR's STI program is designed to provide employees a competitive incentive plan that focuses on Business Unit ("BU") performance and the performance of the individual and includes a minor component related to EPCOR ("Corporate") financial performance. Target payout levels under the STI program are expressed as a percentage of salary in accordance with EPCOR's STI program.

55. ENGLP has included its target STI amount in its 2018 Forecast, 2019 Bridge Year and 2020 Test Year revenue requirements. Under NRG's ownership STI Plan participation was limited to a few employees. Upon transition to ENGLP, all ENGLP employees were eligible to participate in the STI plan.

56. The relative weightings of the STI Program for 2018 to 2020 are shown in Table 4.3.3.1-3 below.

Table 4.3.3.1-3
Short Term Incentive Program Measures
Weightings 2018-2020
(%)

		A	B	C
	STI Performance Measure	**2018 F**	**2019 Bridge Year**	**2020 Test Year**
1	Financial Performance	10	10	10
2	BU Activity Measure	90	90	90
3	**Total**	**100**	**100**	**100**

57. The first measure, which accounts for 10% of the overall weighting, is related to achieving a financial performance target. The financial component of STI calculations for ENGLP will be based on net income. The net income target is based on a forecast of the following year's net income. Threshold performance is set at 85% of target net income and stretch performance is set at 115% of target net income.

58. The second measure, which accounts for 90% of the overall weighting, is related to non-financial performance measures focused on three broad categories of activities in the areas of Safety, Operational Efficiency and Customer Service and each category will be weighted equally at 30% and will total to a relative weighting of 90%. These specific activity measures are designed to engage and focus all employees on improving overall performance as a utility service provider.

59. Targets and measures are reviewed and approved by the Human Resources and Compensation Committee of EPCOR's Board of Directors. Performance is measured based on actual performance relative to target performance. Points are awarded based on the weighting assigned to each measure. Actual performance results must achieve a minimum threshold performance of target to be awarded 50% of the points related to that measure. Actual performance that meets the target level of performance will be awarded 100% of the points related to that measure. Performance that exceeds target will be awarded up to 120% of the points related to that measure.

60. The points awarded for each performance measure will be summed to arrive at an overall point total. The overall point total will be used to determine the STI funding amount.

61. The level of the target STI amount for individual employees is set as a percentage of base salary. This ranges from 2.5% for non-Management, 10% for Management and 15% for the General Manager position.

62. The STI calculated amounts will be aggregated into a STI bonus pool. The STI bonus pool will be comprised of the total STI funding amount that relates to the performance level achieved.

63. Individual employee performance will influence the determination of an individual employee's share of the STI bonus pool. Individual employee performance is rated on a scale from “5” to “1”, where the highest rating for “Outstanding” performance is “5”, “Fully Successful” performance is “3”, and the lowest rating for “Unacceptable” performance is “1”. The most common individual performance rating is expected to be a “3”.

Salary Transfers:

64. ENGLP is always seeking operational efficiencies. As EPCOR has other operations in Ontario, where possible ENGLP will look to take advantage of economies of scale across these operations. For the 2019 Bridge year and 2020 Test Period, ENGLP Aylmer is intending to have its General Manager and Administrative & Field Supervisor provide operational management support to ENGLP's Southern Bruce Operations. ENGLP is forecasting that 25% of each of the General Manager and Administrative & Field Supervisor time will be spent supporting Southern Bruce Operations (total of 0.5 FTE). This results in a decrease in employee costs to ENGLP (i.e., salary transfer to Southern Bruce) as reflected in row 7 of Table 4.3.3.1-1.

65. In addition, ENGLP Aylmer employees are also involved in capital projects from time to time. In these instances, their time on capital projects is charged to the capital project and an offsetting reduction is reflected in their operating salaries and results in a reduction in operating employee costs as reflected in row 7 of Table 4.3.3.1-1.

4.3.3.2 Operating Support Costs

66. The following section covers the operating support costs for ENGLP Aylmer. Operating support costs are the operating, maintenance and administrative ("OM&A") cost other than employee compensation, shared service and corporate costs and low income programs as these are discussed in Sections 4.3.3.1, 4.3.3.3 and 4.3.3.6 respectively.

67. Below is a high level description of ENGLP's operating support cost categories for the 2020 Test Year.

Table 4.3.3.2-1
ENGLP's Operating Support Cost Expense Category Description

	Expense Category	A Description
1	Insurance	ENGLP carries insurance coverage for commercial general liability, umbrella, fleet, property & equipment, environmental, transfer stations and business interruption.
2	Utilities	Charges for all utility services
3	Advertising	Products, services, objectives, achievements, and public information disseminated through paid media space (TV, radio, newspaper, periodicals, signage, etc.)
4	Telephone	Cost of telephone service, long distance charges, fax, two-way radios, cellular charges, connect and disconnect charges, data charges for meter monitoring devices and vehicle mobile networking
5	Office & Postage	All stationery, printing and reproduction charges, postage, office supplies, etc. Rental and maintenance of office machine and furniture, and non-capital purchases.
6	Repair & Maintenance	Utility work, service additions, equipment repairs, compressor station maintenance, computer maintenance, small tools, building repair and maintenance, parking lot clearing and maintenance, transfer station maintenance and rental costs of third party equipment.
7	Automotive	Expenses related to vehicle repair, maintenance and fuel
8	Dues & Fees	All costs for licenses, easements, etc. Membership dues paid to professional or service organizations for all employee and corporate memberships.
9	Regulatory	Expenses related to third-party regulatory support as well as one-time costs as identified in Section 4.3.3.5. Also includes a reduction for the portion of expenses that constitute the System Gas Fee.
10	Bad Debts	Write-off of estimated uncollectible accounts.
11	Interest - Security Deposits	Interest payments and accrual on intercompany long term debt and interest expense on short-term intercompany debt balances.
12	Bank Charges	Banking and guarantee fees
13	Collection Expense	Fees related to collection of delinquent accounts
14	Travel & Ent.	Travel costs for business and training including airfare, accommodations, car rentals, taxis and meals.
15	Legal	Costs incurred to obtain legal advice and representation in matters that are outside of the normal regulatory process such as commercial and employment law matters.
16	Audit	All charges and related expenses from firms and individuals providing audit and assurance services.
17	Consulting Fees	This category consists of consulting fees for engineering and meter reading services.
18	Management Fees	This category consists of payment to Ayerswood by NRG for finance, accounting, and senior management oversight. ENGLP notes that these fees are no longer applicable since the transition to EPCOR in November 2017.

68. ENGLP has provided a summary of historical costs and forecasted costs by expense category from 2011 to 2020 in Table 4-3.3.2-2 below.

Table 4.3.3.2-2
Operating Support Costs
($'s)

		A	B	C	D	E	F	G	H	I	J	K
	Expense Category	**OEB Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A[1]**	**2018 F**	**2019 Bridge**	**2020 Test**
1	Insurance	259,345	277,066	285,902	274,243	164,744	174,538	179,774	169,301	79,707	82,895	86,211
2	Utilities	18,061	11,199	9,832	11,043	9,825	10,765	11,900	9,525	10,478	16,573	17,443
3	Advertising	56,500	43,906	65,336	56,243	47,948	54,432	65,529	35,082	34,455	60,936	34,240
4	Telephone	65,159	39,565	30,017	28,282	26,839	28,444	29,900	27,596	41,646	27,600	36,000
5	Office & Postage	127,928	99,383	101,115	107,600	115,485	130,398	133,000	118,430	156,645	126,074	127,394
6	Repair & Maintenance	226,054	143,067	158,552	163,360	155,983	186,338	219,780	106,204	185,831	199,943	198,122
7	Automotive	71,000	53,463	68,809	61,378	81,090	65,516	72,000	57,628	50,927	44,807	45,748
8	Dues & Fees	41,705	29,418	61,976	47,912	34,255	34,835	35,880	18,007	29,740	29,922	31,185
9	Mapping Expense	919	-	-	-	-	-	-	-	-	-	-
10	Regulatory	111,000	278,576	246,479	400,906	1,036,973	225,356	213,500	63,010	887,337	206,920	211,852
11	Bad Debts	60,000	32,400	200	29,689	32,034	37,166	40,000	24,594	30,486	34,200	34,200
12	Interest - Security Deposits	6,432	1,879	2,778	1,099	2,298	-4,831	2,000	865	-	-	-
13	Bank Charges	17,749	48,840	26,202	18,764	20,319	14,908	18,500	34,419	14,629	6,003	6,019
14	Collection Expense	20,000	8,008	8,352	7,017	11,408	7,942	8,800	4,847	-	-	-
15	Travel & Ent.	4,150	3,328	3,800	3,207	6,146	8,210	9,000	3,525	13,493	12,788	15,145
16	Legal	54,432	25,165	2,304	14,465	15,945	205,339	295,000	985,130	30,456	33,759	34,468
17	Audit	20,000	15,975	26,772	18,000	19,750	18,000	33,000	24,000	57,750	30,690	31,334
18	Consulting Fees	64,560	37,675	46,216	44,684	53,441	40,181	100,000	3,490	389,445	200,398	116,913
19	Management Fees	235,157	457,020	457,020	457,020	457,020	457,020	457,020	457,020	-	-	-
20	Correction on CCA issue	(75,000)	-	-	-	-	-	-	-	-	-	-
21	Miscellaneous	25,000	-	-	-	-	-	-	-	1,053	-	-
22	**Total**	**1,410,151**	**1,605,933**	**1,601,662**	**1,744,912**	**2,291,503**	**1,694,557**	**1,924,583**	**2,142,674**	**2,014,078**	**1,113,508**	**1,026,274**

Note 1: Years 2011-2017 based on fiscal period from October to September. Years 2018 -2020 based on fiscal period from January to December.

69. ENGLP has established a threshold of $0.05 million ($50,000) per expense category for variances requiring explanations, as per the Board's requirements. A summary of variances by expense category in Table 4.3.3.2-3 below. The variances are between:

- 2011 Actual vs 2011 OEB Approved
- 2018 Forecast vs 2017 Actual
- 2019 Bridge vs 2018 Forecast
- 2020 Test vs 2019 Bridge

Table 4.3.3.2-3
Year over Year Variance
($)

	Expense Category	A **2011 Actual vs 2011 OEB Approved**	B **2018 Forecast vs 2017 Actual**	C **2019 Bridge vs 2018 Forecast**	D **2020 Test vs 2019 Bridge**
1	Insurance	17,721	(89,594)	3,188	3,316
2	Utilities	(6,862)	953	6,095	870
3	Advertising	(12,594)	(627)	26,481	(26,696)
4	Telephone	(25,594)	14,050	(14,046)	8,400
5	Office & Postage	(28,545)	38,215	(30,571)	1,320
6	Repair & Maintenance	(82,987)	79,627	14,112	(1,821)
7	Automotive	(17,537)	(6,701)	(6,120)	941
8	Dues & Fees	(12,287)	11,733	182	1,263
9	Mapping Expense	(919)	-	-	-
10	Regulatory	167,576	824,327	(680,417)	4,932
11	Bad Debts	(27,600)	5,892	3,714	-
12	Interest - Security Deposits	(4,553)	(865)	-	-
13	Bank Charges	31,091	(19,790)	(8,626)	16
14	Collection Expense	(11,992)	(4,847)	-	-
15	Travel & Ent.	(822)	9,968	(706)	2,358
16	Legal	(29,267)	(954,674)	3,303	709
17	Audit	(4,025)	33,750	(27,060)	644
18	Consulting Fees	(26,885)	385,955	(189,047)	(83,485)
19	Management Fees	221,863	(457,020)	-	-
20	Correction on CCA issue	75,000	-	-	-
21	Miscellaneous	(25,000)	1,053	(1,053)	-
22	**Total**	**195,782**	**(128,596)**	**(900,570)**	**(87,234)**

70. ENGLP has provided historical information (i.e., 2011 to 2017) in Table 4.3.3.2-2 and Table 4.3.3.2-3 above for information purposes only. ENGLP is not in a position to address variance explanations or justify costs prior to its acquisition of the Aylmer operations. Hence, no variance explanations will be provided for 2011 Actual to 2011 OEB approved and year over year actual variances prior to 2018.

71. For the 2018 to 2020 forecast, ENGLP used a bottom-up approach to forecast its operating costs based on Aylmer's operating work requirement with adjustments to known material costs in the 2018 Forecast, 2019 Bridge and 2020 Test Year.

72. ENGLP notes the following likely explanations for some variances over the materiality threshold between 2017 Actuals and 2018 Forecast based on its limited understanding of the 2017 Actuals. With the transition of the assets to ENGLP, insurance is managed by EPCOR's shared insurance and risk resources and the utility has realized some insurance cost savings from economies of scale. The increase in regulatory costs is a reflection of the one-time costs incurred in 2018 for cost of service applications and proceeding EB-2018-0235 as further described in Section 4.3.3.5. The Management Fees from Ayerswood Development Corp. ("ADC") were eliminated with the implementation of EPCOR's shared service model upon transfer of the assets to ENGLP. The increase in Consulting Fees is likely primarily due to addition of the Transitional Services Agreement ("TSA") costs paid to ADC as further described below.

73. From the 2018 Forecast to 2019 Bridge Year, the Regulatory Expense and Consulting Fee categories meet ENGLP's $0.05 million materiality threshold. The $0.66 million decrease in Regulatory Expense (highlighted gray in Table 4.3.3.2-3) is attributed to one-time expenses in 2018 related to the following three regulatory applications:

- EB-2016-0236 - NRG's Cost of Service Application
- EB-2018-0235 - 2018 IRM and Associated filings
- EB-2018-0336 - 2020 Cost of Service Application

74. ENGLP notes that as described in Section 4.3.3.5 (one-time costs) it is proposing to recover one-fifth of one-time costs in the 2020 Test Year to be recorded under regulatory expense. Table 4.3.3.2-4 below summarizes the one-time cost ENGLP is proposing to recover in the 2020 Test Year.

Table 4.3.3.2-4
One-Time Costs Proposed for Recovery
($)

	One-time Cost Item	A Amounts for recovery
1	EB-2018-0235 - 2018 IRM and Associated filings	216,481
2	EB-2018-0336 - 2020 Cost of Service	608,533
3	Development of Standard Operating Procedures	100,000
4	**Total**	**925,014**
5	**Amount included in Test Year (row 4 ÷ 5)**	**185,003**

Note 1: ENGLP notes that is not proposing to recovery costs from EB-2016-0236 as further discussed in Section 4.3.3.5.

75. The $0.19 million decrease in Consulting Fees from 2018 Forecast to 2019 Bridge (highlighted gray in Table 4.3.3.2-3) is primarily due to the TSA costs. These costs are paid to ADC for the transfer of and use of the ADC's rate models and supporting information for NRG's 2016 cost of service filing. ADC was NRG's affiliate company which provided senior management, finance and accounting support to NRG. The total TSA cost is approximately $0.39 million with $0.30 million occurring in 2018 and $0.09 million occurring in 2019.

76. The $0.08 million decrease in Consulting Fees from 2019 Bridge to 2020 Test Year is primarily due to $0.09 million in Transitional Services Agreement costs occurring in 2019 as described above not occurring in 2020.

77. ENGLP's proposed operating support expenditures above will allow for the continued safe, reliable, secure, cost-efficient and environmentally responsible operation of Aylmer's gas distribution system.

4.3.3.2.1 Operating Expenses for Rate 6 (IGPC)

78. This section sets out the annual operating expenses that can be directly attributed to Rate Class 6 (IGPC) in the 2020 Test Year. In total, the costs are forecasted to be $303,283 in 2020, and are comprised of the following amounts in Table 4.3.3.2.1-1.

Table 4.3.3.2.1-1
Summary of IGPC Operating Expense
($)

	Cost Category	A **2019** **Bridge Year**	B **2020** **Test Year**
1	Depreciation Expense	311,066	131,805
2	Enbridge Gas Transportation Charges	-	-
3	Maintenance Costs – Transfer Stations	42,966	44,651
4	Maintenance Costs – Pipeline	33,589	35,021
5	Property Taxes	87,853	91,806
6	**Total**	**475,474**	**303,283**

Depreciation Expense

79. ENGLP proposes to recover $131,805 of depreciation expense in the 2020 Test Year from Rate Class 6 (IGPC). This amount is based on a depreciation expense of $129,448 for the dedicated pipeline, and $2,357 for the meter. The decrease in depreciation expense from 2019 to 2020 is the result of updating the depreciation rates (from 5% to 1.98%) for this pipeline. ENGLP discusses the change in depreciation rates in Section 4.4 below. See Exhibit 2, Tab 1, Schedule 2 for the fixed asset continuity schedules which reflect the change in the depreciation rate.

Enbridge Gas Transportation Charges

80. In December 2018, the Board approved the direct flow-through of the actual costs charged to ENGLP by Union Gas, and in the future Enbridge Gas, under the M9 and Bundled T contracts with Enbridge Gas for the volumes required to serve the customer in Rate 6 in conjunction with moving to a fully fixed distribution rate for Rate 6 effective October 1, 2018.[8] As such, there are no Enbridge Gas transportation charges included in the costs attributable to IGPC for the 2020 Test Year.

Maintenance Costs – Transfer Stations

81. The forecasted maintenance service for the 2020 Test Year is estimated to be $44,651.

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[8] EB-2018-0235 Decision and Order, December 6, 2018, pg. 9 and Settlement Proposal, November 21, 2018, pg. 18.

Maintenance Costs – Pipeline

82. The forecasted maintenance service for the pipeline during the 2020 Test Year is estimated to be $35,021.

Property Taxes

83. ENGLP is proposing to recover $91,806 for property taxes incurred in respect to the IGPC pipeline. This amount is based on a modest increase over 2018 actual property taxes of $87,853. Property taxes are based on a rate/foot ($45.93[9] per foot for IGPC) of pipeline.

4.3.3.3 Shared Service and Corporate Costs

84. As described in Section 4.3.3.2, prior to ENGLP's acquisition of the assets, NRG received services from an affiliate, Ayerswood Development Corp., including regulatory and financial oversight. These costs were reflected in NRG's OM&A costs as Management Fees, and remained consistent over the historical years. ENGLP does not have specific details on the services provided nor the costing of those services. Accordingly, the remainder of the information in this section is related to Shared Services and Corporate Shared Services Costs under ENGLP's ownership.

85. ENGLP's Aylmer operations obtains Shared Services from its affiliate companies EPCOR Water Services Inc. ("EWSI"), EPCOR Commercial Services Inc. ("ECSI") and EPCOR Ontario Utilities Inc. ("EOUI") and its parent EUI ("Corporate Shared Services"). The services provided by these entities are necessary for ENGLP to provide utility services for its Aylmer operations and are comprised of activities that are centrally managed within areas of EUI due to their nature and/or for the purpose of realizing economies of scale and greater effectiveness.

86. Shared Services costs are determined on a cost recovery basis in accordance with the Affiliate Relationship Code for Gas Utilities (ARC) and ENGLP's ARC Compliance Plan and will be delivered in accordance with a Service Level Agreement ("SLA") between the parties. A copy of the SLA template is provided in Exhibit 4, Tab 3, Schedule 1. See Exhibit 4, Tab 3,

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[9] https://www.ontario.ca/laws/regulation/980282, Part X, Table 3.

Schedule 2 for a copy of the signed ARC Certification. The allocation of Shared Services is assessed regularly and adjusted as appropriate.

87. For some functional categories, such as Human Resources, Supply Chain and Public and Government Affairs, services are provided from EUI and EWSI. In these instances, the services provided by EUI tend to be limited to governance, oversight and broad policy considerations, while the services provided by EWSI are more tactical and are driven by the specific business needs of ENGLP.

88. Table 4.3.3.3-1 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's total Shared Services and Corporate Shared Services costs provided to ENGLP for its Aylmer operations.

Table 4.3.3.3-1
Shared Services and Corporate Cost Allocated to ENGLP Aylmer
($)

	Expense Category	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	Affiliate Shared Services	477,608	441,152	453,505
2	Corporate Shared Services	405,984	427,572	439,217
3	**Total Shared Services and Corporate Costs**	**883,592**	**868,724**	**892,722**

Shared Services from ENGLP Affiliates

89. Table 4.3.3.3-2 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's total affiliate Shared Services from EWSI, ECSI and EOUI.

Table 4.3.3.3-2
Affiliate Shared Services Allocated to ENGLP Aylmer
($)

	Affiliate Service Provider	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	EPCOR Water Services	317,608	79,681	81,912
2	EPCOR Commercial Services	83,500	100,808	103,631
3	EPCOR Ontario Utilities	76,500	260,664	267,962
4	**Total**	**477,608**	**441,152**	**453,505**

Shared Services Provided by EWSI

90. The following is a general description of the Shared Services provided by EWSI to ENGLP for the 2020 Test Year:

(a) Supply Chain Management (SCM) - services for purchasing and strategic sourcing including management of the end-to-end procurement process for the goods required by ENGLP.
(b) Public and Government Affairs (P&GA) – services related to internal and external communication and stakeholder and public consultation requirements of ENGLP.
(c) Human Resources (HR) – provides human resource consulting; support of recruitment efforts and disability management for ENGLP employees.
(d) Training and Development – design, develop and delivery of required training, standard operating procedures and training documentation necessary for staff to provide utility services.
(e) Project Management Office (PMO) – provides project controls, governance and project standardization and support for ENGLP. ENGLP notes that PMO costs are capitalized.

91. The Shared Services costs are determined on a cost recovery basis in accordance with the ARC, and ENGLP's ARC Compliance Plan and are reflected in a SLA between the parties. The allocation methodologies have been designed to ensure that the allocation of EWSI's Shared Services costs are fair and reasonable, cost-effective, predictable and reflect the benefit received by function or cost causation. Costs are directly charged based on estimated time spent supporting the Aylmer operations.

92. Table 4.3.3.3-3 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's total EWSI Shared Services costs.

Table 4.3.3.3-3
EWSI Shared Services Costs Allocated to ENGLP Aylmer
($)

		A	B	C
	Shared Service	**2018 F**	**2019 Bridge Year**	**2020 Test Year**
1	SCM	16,140	10,792	11,094
2	P&GA	15,434	16,684	17,151
3	HR	6,352	48,456	49,813
4	Training and Development	43,493	3,749	3,854
5	PMO	-	-	-
6	Other Services	236,190	-	-
7	**Total**	**317,608**	**79,681**	**81,912**
8	Variance		(237,927)	2,231

93. The decrease in EWSI shared costs from the 2018 Forecast to the 2019 Bridge Year are due to the elimination of "Other Services" comprised of management, finance and Shared Services oversight as well as Health Safety & Environment support costs. Moving forward these types of support services will be provided by other EPCOR Affiliates such as ECSI and EOUI as further described below.

94. The overall trend in costs from the 2019 Bridge Year to the 2020 Test Year remains flat with increases primarily due to inflation.

Shared Services Provided by ECSI

95. The following is a general description of the Shared Services provided by ECSI to ENGLP:

(f) Management Oversight – the Senior Vice President of Commercial Services provides general management and oversight to ENGLP as the Vice President, Ontario Region reports directly to this position.

(g) Finance –provides financial services such as financial oversight, financial reporting, asset accounting and financial oversight of capital projects to ENGLP.

96. Table 4.3.3.3-4 below provides information on the cost allocators used to allocate Shared Services costs from ECSI to ENGLP's Aylmer business unit. The Shared Services costs are determined on a cost recovery basis in accordance with the ARC, and ENGLP's ARC Compliance Plan and are reflected in a SLA between the parties. The allocation methodologies

have been designed to ensure that the allocation of ECSI's Shared Services costs are fair and reasonable, cost-effective, predictable and reflect the benefit received by function or cost causation. ECSI's costs are shared amongst all Ontario operations (Aylmer, Southern Bruce[10] and Collingwood) and the non-regulated activities the resources in ECSI support.

Table 4.3.3.3-4
Allocation of ECSI Costs – Cost Allocators

	Responsibility Centre and Function	A Allocator
1	Management Oversight	Estimated of time spent
2	Finance	Composite - Revenue, Assets, Headcount

97. For Finance, costs are first allocated to non-regulated activities based on an estimated time spent supporting these non-regulated activities which is approximately 25%. The remaining 75% of finance costs are then allocated to each Ontario operation (Aylmer, Southern Bruce and Collingwood) based on the Composite cost allocator which factors in the businesses' share of group revenues, assets, and headcount and is consistent with the approach for the allocation of EUI Corporate Shared Services as described in more detail below.

98. Table 4.3.3.3-5 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's total ECSI Shared Services costs.

Table 4.3.3.3-5
ECSI Shared Services Costs Allocated to ENGLP Aylmer
($)

	Shared Service	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
1	Management Oversight	83,500	50,000	51,400
2	Finance	-	50,808	52,231
3	**Total**	**83,500**	**100,808**	**103,631**
4	Variance		17,308	2,823

99. The overall trend in costs from the 2019 Bridge Year to the 2020 Test Year remains flat with increases primarily due to inflation.

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[10] ENGLP's Southern Bruce utility is expected to be operational in late 2019. This date is subject to receiving the necessary regulatory and other approvals as well as other factors.

Shared Services Provided by EOUI

100. The following is a general description of the Shared Services provided by EOUI to ENGLP:

(a) Management Oversight – the Vice President, Ontario Region provides direct management and oversight to the employees of ENGLP's Aylmer business unit, with the General Manager of ENGLP reporting directly into this position.

(b) Finance – Working with the Finance resources in ECSI, Ontario Finance personnel will provide oversight and support of the financial reporting and asset accounting for ENGLP.

(c) Regulatory – support the development, coordination of regulatory applications, monitor and coordinate activities or initiatives from government, departments or agencies that may affect ENGLP and manage the interface between these external stakeholders.

(d) Health, Safety and Environment ("HS&E") – ensure ENGLP's health, safety and environment practices and procedures are well designed and in compliance with legislation and compatible with EUI's safety management standards and procedures as well as working with ENGLP staff to implement those practices and procedures.

(e) Board of Directors – The Board of Directors of EOUI, with EOUI as the general partner of ENGLP, provides governance services to ENGLP.

(f) Ontario Facilities – office space and leasehold costs for EPCOR's Ontario head office employees that support ENGLP.

101. Table 4.3.3.3-6 below provides information on the cost allocators used to allocate Shared Services costs from EOUI to ENGLP's Aylmer business unit. EOUI's costs are shared amongst all Ontario operations (Aylmer, Southern Bruce and Collingwood) and non-regulated activities the resources of EOUI support.

Table 4.3.3.3-6
Allocation of EOUI Costs – Cost Allocators

	Responsibility Centre and Function	A Allocator
1	Management Oversight	Composite - Revenue, Assets, Headcount
2	Finance	Composite - Revenue, Assets, Headcount
3	Regulatory	Composite - Revenue, Assets, Headcount
4	HSE	Functional Cost Causation – Headcount
5	Board of Directors	Functional – Costs split evenly across locations
6	Ontario Facilities	Composite - Revenue, Assets, Headcount

102. For Office Facilities, these costs are first allocated to non-regulated activities based on an estimated time the space will be used to support non-regulated activities which is approximately 50%. The remaining 50% of Office Space costs are then allocated to all Ontario operations (Aylmer, Southern Bruce and Collingwood) based on the Composite cost allocator which factors in the businesses' share of group revenues, assets, and headcount and is consistent with the approach for the allocation of EUI Corporate Shared Services as described in more detail below.

103. For the Board of Director function, the Board provides governance services to ENGLP Aylmer and Southern Bruce locations and the Board costs are split evenly across these two locations for 2019 and 2020. For 2018, all Board costs were allocated to the Aylmer location as it was the only location in service in 2018.

104. Table 4.3.3.3-7 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's total EOUI Shared Services costs.

Table 4.3.3.3-7
EOUI Shared Services Costs Allocated to ENGLP Aylmer
($)

	Shared Service	A 2018 F	B 2019 Bridge Year	C 2020 Test Year
1	Management Oversight	28,001	56,453	58,034
2	Finance	-	42,340	43,526
3	Regulatory	30,404	84,680	87,051
4	HSE	-	46,552	47,855
5	Board of Directors	9,333	6,000	6,168
6	Office Facilities	8,761	24,638	25,328
7	**Total**	**76,500**	**260,664**	**267,962**
8	Variance		184,164	7,299

105. The increase in EOUI shared costs from the 2018 Forecast to the 2019 Bridge Year is due to the Finance, Regulatory and HS&E support services being provided by EOUI instead of EWSI.

106. The overall trend in costs from the 2019 Bridge Year to the 2020 Test Year remains flat with increases primarily due to inflation.

Corporate Shared Services from EUI

107. ENGLP obtains Corporate Shared Services from its parent corporation, EUI. The amounts paid by ENGLP to EUI in respect of these services (referred to collectively as Corporate Shared Services costs) include Corporate Shared Service Charges and Corporate Asset Usage Fees, the latter being costs associated with the general plant assets used by EUI in providing Corporate Shared Services to ENGLP. The Corporate Shared Services Charges and Corporate Asset Usage Fees are determined on a cost recovery basis in accordance with the ARC and ENGLP's ARC Compliance Plan. The Corporate Shared Services Charges and Corporate Asset Usage Fees are reflected in a SLA between ENGLP and EUI.

108. Table 4.3.3.3-8 below shows the 2018 Forecast, 2019 Bridge Year and 2020 Test Year's Corporate Shared Services costs charged to ENGLP Aylmer.

Table 4.3.3.3-8
Corporate Shared Services Costs Charged to ENGLP 2018-2020
($)

	Expense Category	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	Corporate Costs Directly Assigned	80,014	88,936	91,080
2	Corporate Costs Allocated	252,513	256,184	265,112
3	Corporate Asset Usage Fees	73,457	82,452	83,025
4	**Total ENGLP Costs**	**405,984**	**427,572**	**439,217**
5	Variance		21,588	11,645

109. Consistent with the approach applied in previous years for all its regulated and non-regulated businesses and as filed with the Alberta Utilities Commission in EUI's Inter-Affiliate Code of Conduct for its regulated utilities in Alberta, EUI allocates Corporate Shared Services costs to EUI business units using the following five step process:

(a) Categorize Corporate Shared Services costs as directly assignable or allocable.
(b) Assign directly assignable costs to the appropriate business unit.
(c) Review/develop/modify allocation method for allocable costs.
(d) Apply allocation method to allocable costs.
(e) Conduct a final review for reasonableness.

Step 1 - Categorize Corporate Shared Services costs as either directly assignable or allocable.

110. The first step in developing Corporate Shared Services charges was to review the components of Corporate Shared Services costs and categorize them into two defined groups:

- Directly assignable costs.
- Allocable costs.

111. Directly assignable costs are those costs that are directly associated with a particular business unit's activity or operation. The relevant Corporate Shared Services department and business unit work together to determine the quantum of directly assigned costs, if any, related to the Corporate Shared Service in question.

112. Allocable costs are those costs that provide benefits to EUI businesses but by their nature cannot be directly assigned and are charged to business units using appropriate cost allocators. These costs are allocated among EPCOR business units using cost allocators that reflect the factor or factors that drive the cost of providing the Corporate Shared Service to each business unit.

Step 2 - Assign directly assignable costs to business units

113. Once the directly assignable costs are identified and determined they are charged directly to each business unit. Directly assignable costs are included in the budgets of the business units and are not included in the budgets of the respective Corporate Shared Service departments.

Step 3 - Review/develop/modify allocation method for allocable costs

114. 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 benefit received by function or cost causation and provides for consistency with the transfer pricing principles in the ARC, ENGLP's ARC Compliance Plan, and EUI's Inter-Affiliate Code of Conduct.

115. The costs associated with the Corporate Shared Services departments, except for the Treasury department, are allocated on one of two bases: (i) using a "functional cost causation allocator"; or (ii) using a "composite cost allocator". The allocation methods used for Treasury costs are different as reflected in rows 18-19 of Table 4.3.3.3-9, below. For Corporate Asset Usage fees, the allocation method is further described in rows 30-35 of Table 4.3.3.3-9, below.

116. A functional cost causation allocator has been used where the costs can be logically allocated using an identified cost causation driver, such as headcount. The composite cost allocator has been used where the costs cannot be allocated using a particular functional cost causation allocator. The latter types of costs tend to be related to Corporate Shared Services that are of a governance nature, and it is appropriate that these types of costs be allocated based on a composite cost allocator which factors in the business unit's share of EUI's total revenues, assets, and headcount.

117. The allocation methods applicable to EUI's allocable Corporate Shared Services costs are summarized in Table 4.3.3.3-9 below.

Table 4.3.3.3-9
EUI's Allocators to ENGLP Aylmer

	Department and Function	A Allocators
	Supply Chain Management	
1	Mailroom	Functional Cost Causation - Headcount
2	Disaster Recovery Planning	Functional Cost Causation - Direct IS Costs
3	Procurement	Functional Cost Causation - Purchase Order Lines
4	Real Estate	Composite - EUI Revenue, Assets, Headcount
5	Security	Functional Cost Causation - Headcount
6	SCM Corporate	Composite - EUI Revenue, Assets, Headcount
	Human Resources	
7	Total Rewards	Functional Cost Causation - Headcount
8	Human Resources Consulting	Functional Cost Causation - Headcount
9	Talent Management	Functional Cost Causation - Headcount
	Information Services	
10	Major Capital Projects	Functional Cost Causation - Headcount
11	Application Services	Functional Cost Causation - Headcount
12	Infrastructure Operations	Functional Cost Causation - Direct IS Costs
	Corporate Finance Services	
13	Corporate Finance	Composite - EUI Revenue, Assets, Headcount
14	Accounts Payable	Functional Cost Causation - Number of Invoices
15	Management Development Program	Composite - EUI Revenue, Assets, Headcount
16	Centre of Excellence	Composite - EUI Revenue, Assets, Headcount
	Executive and Executive Assistants	
17	Executive and Executive Assistants	Composite - EUI Revenue, Assets, Headcount
	Treasury	
18	Treasurer - Corporate Finance	40% PP&E, 30% CapEx, 30% Acquisitions
19	Treasury Operations	50% of (NI + Depreciation), 50% Debt
	EUI Board	
20	All Costs	Composite - EUI Revenue, Assets, Headcount
	Audit and Risk Management	
21	Internal Audit	Composite - EUI Revenue, Assets, Headcount
22	Insurance and Risk Management	PP&E
	Public and Government Affairs	
23	VP Public & Government Affairs	Functional Cost Causation - Weighted Average of Costs for P&GA
24	Corporate Communications	Functional Cost Causation - Net Income
25	Government Relations	Functional Cost Causation - EUI Revenue, Assets, Headcount
26	Community Relations	Functional Cost Causation - Net Income
	Legal Services	
27	Legal Services	Composite - EUI Revenue, Assets, Headcount
	Health, Safety and Environment	
28	All Functions	Functional Cost Causation - Headcount
	Incentive Compensation	
29	All Costs	Average Corporate Cost Allocation
	Asset Usage Fees	
30	Leasehold Asset Costs - Disaster Recovery Leaseholds and EPCOR Tower (Leasehold Improvements)	Occupancy of EPCOR Tower and Business Unit's Proportionate Share of Corporate Services
31	Human Resources Information Services	Headcount
32	Information System Infrastructure	Allocated to each business unit on the basis of the amount of the business unit's weighted average allocation of the Corporate Services departments' operating costs.
33	Financial Systems	i) weighted average operating costs related to finance and ii) payroll function and the weighted average number of Purchase Order Lines by business unit
34	Furniture and Fixture Assets	Occupancy of EPCOR Tower and Business Unit's Proportionate Share of Corporate Services
35	Vehicles	Business unit's proportionate share of allocated Corporate Services costs

118. The allocation percentages used in developing the 2019 Bridge Year and 2020 Test Year were based on EUI's 2018 Budget. Table 4.3.3.3-10 below summarizes the allocation percentages reflected in the in the 2019 Bridge Year and 2020 Test Year.

Table 4.3.3.3-10
Corporate Shared Services Allocation Percentages 2019-2020

		A	B	C	D	E	F	G
		EDTI	**EEA**	**ENGLP Aylmer**	**Other**	**CDN Total**	**EPCOR USA**	**Total**
	Functional Cost Causation Allocators							
1	Headcount	732	319	17	2,049	3,117	316	3,433
2	CAD Headcount percentage	23.5%	10.2%	0.5%	65.7%	100.0%	0.0%	100.0%
3	Headcount percentage	21.3%	9.3%	0.5%	59.7%	90.8%	9.2%	100.0%
4	Assets	2,445.20	190.20	25.08	7,003.61	9,664.10	1,320.19	10,984.29
5	Assets percentage	22.3%	1.7%	0.2%	63.8%	88.0%	12.0%	100.0%
6	PP&E	2,339.33	1.78	19.86	6,634.84	8,995.81	1,264.52	10,260.34
7	PP&E percentage	22.8%	0.0%	0.2%	64.7%	87.7%	12.3%	100.0%
8	CapEx	205.27	1.04	1.91	428.54	636.76	100.58	737.34
9	CapEx percentage	27.8%	0.1%	0.3%	58.1%	86.4%	13.6%	100.0%
10	Debt	1,358.21	20.00	8.66	1,769.26	3,156.13	636.67	3,792.80
11	Debt percentage	35.8%	0.5%	0.2%	46.6%	83.2%	16.8%	100.0%
12	Revenues	696.71	438.74	7.94	753.58	1,896.97	239.95	2,136.92
13	Revenues percentage	32.6%	20.5%	0.4%	35.3%	88.8%	11.2%	100.0%
14	Depreciation	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
15	Depreciation Percentage	29.1%	2.3%	0.2%	51.0%	82.7%	17.3%	100.0%
16	Net Income	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
17	Net Income Percentage	35.1%	13.3%	0.9%	41.9%	91.2%	8.8%	100.0%
18	Direct IS	2.50	1.45	0.05	4.13	8.13	1.96	10.09
19	CAD Direct IS percentage	30.8%	17.8%	0.6%	50.8%	100.0%	0.0%	100.0%
20	Direct IS percentage	24.8%	14.4%	0.5%	41.0%	80.6%	19.4%	100.0%
21	Invoice Lines	110,431	8,419	2,460	312,060	433,370	0.00	433,370
22	Invoice Lines percentage	25.5%	1.9%	0.6%	72.0%	100.0%	0.0%	100.0%
23	PO Lines	10,246	162	90	19,464	29,962	0	29,962
24	PO Lines percentage	34.2%	0.5%	0.3%	65.0%	100.0%	0.0%	100.0%
25	Acquisitions	2	1	0	3	6	5	11
26	Acquisitions percentage	18.2%	9.1%	0.0%	27.3%	54.5%	45.5%	100.0%
	Treasury Allocators							
27	**Treasurer - Corporate Finance Allocator**							
28	PP&E %	22.8%	0.0%	0.2%	64.7%	87.7%	12.3%	100.0%
29	Calculation Weighting %	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
30	**Weighting - PP&E**	**9.1%**	**0.0%**	**0.1%**	**25.9%**	**35.1%**	**4.9%**	**40.0%**
31	CapEx %	27.8%	0.1%	0.3%	58.1%	86.4%	13.6%	100.0%
32	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
33	**Weighting - Cap Ex**	**8.4%**	**0.0%**	**0.1%**	**17.4%**	**25.9%**	**4.1%**	**30.0%**
34	Acquisitions %	18.2%	9.1%	0.0%	27.3%	54.5%	45.5%	100.0%
35	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
36	**Weighting - Acquisitions**	**5.5%**	**2.7%**	**0.0%**	**8.2%**	**16.4%**	**13.6%**	**30.0%**
37	**Total - All Weightings - Treasurer Corporate Finance Allocation**	**22.9%**	**2.8%**	**0.2%**	**51.5%**	**77.3%**	**22.7%**	**100.0%**
38	**Treasury Operations - Allocator**							
39	Weighting - Net Income + Depreciation	32.1%	7.8%	0.6%	46.5%	86.9%	13.1%	100.0%
40	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
41	**Weighting - Net Inc + Depn**	**16.0%**	**3.9%**	**0.3%**	**23.2%**	**43.5%**	**6.5%**	**50.0%**
42	Debt %	35.8%	0.5%	0.2%	46.6%	83.2%	16.8%	100.0%
43	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
44	**Weighting - Debt**	**17.9%**	**0.3%**	**0.1%**	**23.3%**	**41.6%**	**8.4%**	**50.0%**
45	**Total - NI & Depn + Debt - Treasury Operations Allocation**	**34.0%**	**4.2%**	**0.4%**	**46.5%**	**85.1%**	**14.9%**	**100.0%**
	Composite Cost Causation Allocator							
46	**2018F Composite Cost Causation Allocator**							
47	Revenues	32.6%	20.5%	0.4%	35.3%	88.8%	11.2%	100.0%
48	Assets	22.3%	1.7%	0.2%	63.8%	88.0%	12.0%	100.0%
49	Headcount	21.3%	9.3%	0.5%	59.7%	90.8%	9.2%	100.0%
50	**Average - Composite Cost Causation Allocator**	**25.4%**	**10.5%**	**0.4%**	**52.9%**	**89.2%**	**10.8%**	**100.0%**

Step 4 – Apply allocation methods to allocable costs

119. Once the allocation methods were determined, they were applied against EUI's final budgeted Corporate Shared Services costs to arrive at the amounts charged to each business unit.

Step 5 - Final review of Corporate Shared Services Charges for reasonableness

120. The resulting Corporate Shared Services charges were carefully reviewed by management to confirm that the process set out above was properly applied, and that the resulting charges were reasonable.

Directly Assigned Corporate Services Costs

121. The following is a general description of the Corporate Shared Services costs that are directly assigned to ENGLP:

- Information Services ("IS") Application Support – in this cost category are large business unit specific applications. The support costs for each application are recorded in general ledger accounts specific to the application.
- IS Infrastructure Operations – this cost category is made up of charges for the servers, storage, user devices, network and employee services (i.e., service desk services, licensing).

122. Table 4.3.3.3-11 shows the Corporate Shared Services costs for the 2018 Forecast, 2019 Bridge Year and 2020 Test Year that are directly assigned to ENGLP for IS Application Support and IS Infrastructure Support (i.e., desktops, servers, network, databases, printers, etc.). The amount related to Health & Safety for the 2018 Forecast is related to the costs to the implementation of the MoveSafe initiative to educate employees to incorporate specific movements into their daily lives to minimize risk of injury.

Table 4.3.3.3-11
Directly Assigned Corporate Services Costs to ENGLP 2018-2020
($)

	Expense Category	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	IS Application Support	37,016	42,915	44,508
2	IS desktops, printers and network support	40,133	46,021	46,572
3	Health & Safety	2,865	-	-
4	**Total ENGLP Costs**	**80,014**	**88,936**	**91,080**
5	Variance		8,922	2,144

123. The overall trend in costs from the 2019 Bridge Year to the 2020 Test Year remains flat with increases primarily due to inflation.

Allocated Corporate Shared Services Costs

124. The following is a general description of the Corporate Services costs that are allocated to ENGLP:

- Supply Chain Management (SCM) includes mailroom, disaster recovery planning facilities, procurement, real estate, security and space rent of EPCOR Tower located in Edmonton which houses the majority of the Corporate Shared Service employees.
- Human Resources (HR) includes the administration and management of employee compensation and benefits programs; administration and management of payroll functions; human resource consulting; support of recruitment efforts, job and organizational design, and succession and workforce planning; labour and employee relations; administration and management of Human Resource and Information System (HRIS); and the delivery of professional development courses across all EPCOR business units and Corporate Shared Services departments.
- Information Services (IS) manages the implementation of major applications and the installation of major computer hardware devices, user support services related to shared business system applications and the operation and maintenance of the computer hardware platforms (i.e., servers, networks, etc.) and operating systems that shared applications (i.e., Oracle business system) and business unit specific systems applications.

- Corporate Finance Services includes Corporate Finance (taxation, corporate accounting, consolidated reporting and analysis and audit fees), accounts payable, management development of junior level finance employees and centre of excellence (i.e., best practices, support and training for the Oracle Financial suite of products.)
- Executive and Executive Assistants provide governance and leadership services to EUI subsidiaries.
- Treasury performs the services associated with raising capital and provides banking and cash management services to EPCOR subsidiaries. These costs are allocated using a composite of net income, depreciation and debt.
- Board Costs includes EUI’s Board of Directors that provide corporate governance functions to EPCOR and its subsidiaries.
- Audit and Risk Management provides audit and ensures compliance the Canadian legislation equivalent to the United States’ Sarbanes-Oxley Act (commonly referred to as “CSOx”) and provides insurance and Enterprise Risk Management services to EPCOR subsidiaries.
- Public and Government Affairs (P&GA) provides internal/external communication services, liaison services and briefing support in relation to all three levels of government (federal, provincial, and municipal), as well as government agencies and staff, with respect to existing or proposed policies and legislation and community relations (i.e., community engagement tools, processes and investment strategies to support EPCOR’s reputation and relationship objectives. ENGLP notes that a portion of Community Relations costs includes community donations and these costs have been removed and not included in the revenue requirement.
- Legal Services provides legal, governance, and compliance related activities to ENGLP and other EUI business units and subsidiaries.
- Health, Safety and Environment (HSE) provides governance, maintenance, and ongoing implementation of HSE requirements, HSE reporting and plans and related program administration (i.e., Alcohol and Drug Program).
- Incentive Compensation is paid to Corporate Shared Services employees based on individual performance ratings and EUI’s overall annual corporate targets. EUI’s structure for compensating its non-union employees has four components: base compensation (annual salary), employer paid benefits, Short Term Incentive (STI), and Medium Term Incentive (MTI) for participating directors, vice

presidents and executives. EUI's structure for compensating unionized employees has three components: base compensation (hourly wages / annual salaries), employer paid benefits and STI. The compensation was designed to bring employee total compensation to a level which is at par with comparable positions in the market from which EUI must draw employees (i.e., to market value). The program itself is not a separate service, but the costs of any incentives are tracked separately.

125. ENGLP's Allocated Corporate Shared Services costs for the 2018 Forecast, 2019 Bridge Year and 2020 Test Year are shown in Table 4.3.3.3-12 below.

Table 4.3.3.3-12
EUI Corporate Shared Services Costs Allocated to ENGLP 2018-2020
($)

	Function	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	SCM	28,930	28,633	29,240
2	HR	36,997	36,454	41,283
3	IS	56,866	57,129	56,939
4	Corporate Finance Services	19,384	19,267	19,780
5	Executive and Executive Assistants	11,245	11,167	11,502
6	Treasury	3,857	4,199	3,788
7	Board	7,169	6,193	6,221
8	Audit and Risk Management	6,713	5,790	5,911
9	P&GA	39,890	47,947	50,619
10	Legal Services	9,850	9,448	9,812
11	HSE	4,212	3,795	3,922
12	Incentive Compensation	27,400	26,162	26,095
13	**ENGLP Total**	**252,513**	**256,184**	**265,112**
14	Variance		3,671	8,928

126. Overall the allocated Corporate Shared Services costs to ENGLP from EUI remain flat over the 2018 to 2020 period with year over year increases primarily due to inflation.

Allocated Corporate Asset Usage Fees

127. EUI charges fees relating to general plant assets owned by EUI that are used in providing Corporate Shared Services to EPCOR business units. These fees are referred to as Corporate Asset Usage Fees. The categories of assets for which Corporate Asset Usage Fees are charged include the following:

- Leasehold Assets – disaster recovery and EPCOR Tower leasehold improvements benefitting employees in Corporate Shared Services departments that work at EPCOR Tower and support EUI subsidiaries including ENGLP.
- Human Resources Information Systems (HRIS) - software application that is used by EUI's HR department to manage the employees of the EPCOR group, including such things as recruiting, hiring, managing and paying employees (including the calculation of pensions, CPP, UIC, income tax and other payroll deductions).
- Information Services (IS) Infrastructure - IS assets include servers, electronic storage devices, information system networks, desktops and IS Applications.
- Financial Systems - represent the current financial application that is used to pay invoices, record and report financial information, prepare financial statements, calculate depreciation, purchase goods and services and manage project costs. The software application, Oracle Financials, uses modules that include Accounts Payable, Accounts Receivable, General Ledger, Purchasing, Projects and Fixed Assets.
- Furniture and Fixture Assets - represent furniture such as offices, workstations, chairs, tables, file cabinets and shelves used by employees in Corporate Shared Services departments.
- Vehicles - Vehicle assets are used for security and for employees at EPCOR Tower to travel to meetings at EUI sites in performing the services they provide in support of EUI and its subsidiaries.

128. The Asset Usage Fee for each category of corporate assets is comprised of two components: "return on" capital and "return of" capital (or depreciation expense). The return on capital component is calculated using the service recipient's weighted average cost of capital ("WACC").

129. EUI's 2018 Forecast, 2019 Bridge Year and 2020 Test Year's Asset Usage Fees allocated to ENGLP are shown in Table 4.3.3.3-13.

Table 4.3.3.3-13
Corporate Asset Usage Fees to ENGLP 2018-2020
($)

	Asset Category	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	Leasehold Assets	4,291	4,478	4,472
2	HRIS	1,865	2,100	2,492
3	IS Infrastructure	55,639	63,939	65,514
4	Financial Systems	8,762	9,078	8,644
5	Furniture and Fixtures	2,875	2,857	1,882
6	Vehicles	25	-	21
7	**Total ENGLP**	**73,457**	**82,452**	**83,025**
8	Variance		8,995	573

130. For the 2019 Bridge year and 2020 Test Year, the IS Infrastructure increases are primarily due to annual capital projects for facilities, network, server and storage, telecommunication infrastructure to support incremental growth and to replace assets that will reach the end of their useful lives or require upgrading.

4.3.3.4 Purchase of Non-Affiliate Services

131. ENGLP utilizes external suppliers, contractors or consultants (“Contractors”) to carry out work for which it does not have the internal expertise or specialized equipment to cost effectively complete the work. From an overall cost perspective, it is less expensive for ENGLP to use Contractors for these activities compared to maintaining the staff and/or equipment necessary to competently carry out this work internally. At times, ENGLP may work with Contractors to manage work “peaks” associated with higher than normal work levels, “one off” projects, and to execute work to meet timelines as necessary. ENGLP does not overstaff its Aylmer operations in order to handle peak work-loads as hiring additional staff has associated higher costs.

132. ENGLP’s Contractor costs in OM&A are found in consulting expenses, repairs and maintenance and in regulatory. The consulting expense category is made up of a number of small contracts with the most significant being the outsourcing of the meter reading function. The forecasted costs for this contractor are approximately $80,000 for the 2019 Bridge and the 2020 Test Year. The remaining costs in the consulting expense category are approximately $35,000 for the 2019 Bridge and the 2020 Test Year and these costs are spread over thirteen Contractors.

133. Contractor costs in the repairs and maintenance category are mainly for maintenance of the IGPC regulating station and pipeline infrastructure. The forecasted costs included in repairs and maintenance for this contractor are approximately $80,000 in the 2019 Bridge and the 2020 Test Year.

134. Furthermore, in the regulatory expense category, outside of the one-time costs discussed in Section 4.3.3.5, costs are approximately $30,000 for the 2019 Bridge and the 2020 Test Year. These costs are spread over four contractors.

135. EPCOR's procurement policy, which is included as Exhibit 4, Tab 3, Schedule 3, is applicable to all its subsidiaries. The policy highlights EPCOR's policy and guidelines over the procurement of goods and services. Schedule-A of the policy includes levels of signing authority for procurement of goods and services.

136. EPCOR abides by the New West Partnership Trade Agreement (NWPTA), which stipulates most pieces of work greater than $75,000 (greater than $200,000 for construction) in value should be competitively bid through a public posting process if there is not an existing agreement in place that can be leveraged. EPCOR also adheres to all Canadian trade partnership agreements as applicable, such as the Comprehensive Economic Trade Agreement and Canadian Free Trade Agreement.

137. ENGLP, as part of the ongoing integration into EPCOR since the acquisition of the utility assets, is in the process of implementing EPCOR's procurement policy and expects the policy to be fully implemented in 2019. ENGLP will follow a materiality threshold for transactions of $75,000, consistent with EPCOR's procurement policy.

138. To ensure business continuity over 2017 and 2018, ENGLP has continued to sole source some contractors which NRG had previously utilized for a number of years. The contractors are familiar with Aylmer's gas distribution system and ENGLP's standards and practices and customer service policies, thereby ensuring that the work will be completed in accordance with these standards. The work that has been sole sourced includes:

- Meter reading services - The contractor performing the meter reading function has been used by NRG for 15 years prior to the acquisition of the assets by ENGLP. The costs for this item are captured under the consulting expense category of OM&A.

- Work on IGPC regulating station and pipeline infrastructure – The contractor that performs this work performed the construction of the assets and has maintained the assets since and is therefore best suited to perform the work and ensure the assets are maintained appropriately. This contractor was also contracted to complete the recent upgrades to the facilities for the same reason. The costs related to this work are included in repairs and maintenance or are captured as a part of the capital expenditures depending on the nature of the work.
- Pipeline construction services – ENGLP sources a local underground construction company and a local directional drilling company for pipeline construction services both of which have been used by NRG for this work for a significant number of years. The costs related to this work are included in capital expenditures.

4.3.3.5 One-Time Costs

139. The regulatory, legal, and consulting expense categories show relatively high volatility over the historical period during which NRG owned the assets. This suggests that NRG incurred one-time costs in these areas at some points, particularly over the years 2013 through 2017. The explanations provided for actuals for the years 2014 and 2015 in the evidence NRG filed for EB-2016-0236 support the thought that NRG incurred one-time costs in these areas in the years noted above.

140. ENGLP has identified a total of $1,113,350 in one-time costs for the 2018 Forecast year, 2019 Bridge Year and 2020 Test Year, of which ENGLP is proposing to only recover $925,014 in this Application. Table 4.3.3.5-1 below outlines the one-time costs pertaining to each of the years identified. The amounts identified for the 2018 Forecast year and 2019 Bridge Year are included in regulatory costs as part of the operating support costs in Section 4.3.3.2 for those years in Table 4.3.3.2-2. The item expected to be incurred in the 2020 Test Year has not been included in the OM&A forecast for that year, instead the one-time annual amount proposed for recovery in paragraph 5, below has been included in regulatory costs for the 2020 Test Year.

141. The one-time costs identified are comprised of regulatory expenses for cost of service applications and proceeding EB-2018-0235, and costs associated with developing standard operating procedures. ENGLP has included one-fifth of the one-time costs identified in Table 4.3.3.5-2 in its revenue requirement, assuming a five year period until the next cost of service application is filed.

142. Regulatory costs related to QRAM and Price Cap IR applications are considered to be ongoing costs throughout the 2020 to 2024 period and are therefore included within the OM&A costs in the Application as reflected in Table 4.3.3.2-2. Each of the one-time cost categories in Table 4.3.3.5-1 are described further below.

Table 4.3.3.5-1
Total One-time Costs for 2018, 2019 and 2020
($)

	One-time Cost Category	A **2018 F**	B **2019 Bridge Year**	C **2020 Test Year**
1	EB-2016-0236 - NRG's Cost of Service Application	188,336	-	-
2	EB-2018-0235 - 2018 IRM and Associated filings	216,481	-	-
3	EB-2018-0336 - 2020 Cost of Service	425,213	183,320	-
4	Development of Standard Operating Procedures	-	-	100,000
5	**Total**	**830,030**	**183,320**	**100,000**

143. Included in the identified one-time costs for 2018, 2019 and 2020 are the following items:

- Costs related to EB-2016-0236, NRG's cost of service application filed in 2016. On August 9, 2016, NRG filed a rate application (EB-2016-0236) for the period October 1, 2016 to September 30, 2021. NRG incurred $188,336 in costs related to the preparation of this application which was recorded by NRG as a deferred charge asset in 2016. This application was subsequently put in abeyance pending the Board's decision on NRG's MADD Application (EB-2016-0351) which requested approval to transfer its natural gas distribution system to ENGLP. NRG's application to transfer the natural gas distribution assets to ENGLP was approved by the Board on August 3, 2017 and the transaction closed on November 1, 2017. As the proceeding was still in abeyance when the assets transitioned to ENGLP, the $188,336 in costs incurred by NRG formed part of the assets acquired by ENGLP. ENGLP has written the associated deferred charges off in 2018 given that it was not seeking recovery of these costs as further discussed below. These costs are captured in ENGLP's 2018 Forecast OM&A costs in the regulatory expense line item in Table 4.3.3.2-2.

- Costs related to EB-2018-0235, ENGLP's 2018 IRM and associated applications – these one-time costs are related to the preparation and defense of this application and are incremental to the costs on which rates are based. This application was filed on July 30, 2018 and included proposed IRM adjustments for 2016, 2017 and 2018, an application to dispose of certain deferral and variance account balances, an application to change Rate 6 to a fully fixed rate and an application to align the rate year with the fiscal year. The costs associated with this application include legal and consulting fees of approximately $92,000, and an estimated $10,000 for intervener and Board costs with the remainder made up of fully loaded cost for the affiliated resources that prepared and defended these applications. As ENGLP does not have its own finance and regulatory resources, it relied on affiliated resources from EPCOR Commercial Services Inc. ("ECSI") and EPCOR Water Services Inc. ("EWSI") for these services. These services are incremental to the services provided by these affiliates for which ENGLP receives a cost allocation as described in Section 4.3.3.3. The cost allocation is representative of the resource requirements to support the routine and ongoing operations of ENGLP, not a significant undertaking such as the applications included in EB-2018-0235. These costs are captured in ENGLP's 2018 Forecast OM&A costs in the regulatory expense line item in Table 4.3.3.2-2.

- Costs related to EB- 2018-0336, ENGLP's 2020 Cost of service application – These one-time costs are related to the preparation and defense of this Application and are incremental to the costs on which rates are based. These one-time costs include amounts actually incurred in 2018, as well as the forecasted costs for 2019 associated with defending the Application which are included in the regulatory expense line item of the OM&A costs for these years in Table 4.3.3.2-2. The cost forecast assumes a written proceeding and should this Application require an oral hearing, ENGLP will need to recover additional costs. The costs associated with this Application include expert, legal and consulting fees of approximately $137,000 and estimated intervener and Board costs of $85,000. The remainder of the costs represents fully loaded cost for the affiliated resources from ECSI, EWSI and EPCOR Distribution and Transmission Inc. ("EDTI") responsible for the preparation and defense of the Application. These services are incremental to the services provided by these affiliates for which ENGLP receives a cost allocation as described in Section 4.3.3.3. The allocation is representative of the resource requirements to support the routine and ongoing operations of ENGLP, not a significant undertaking such as a cost of service application. ENGLP notes that EDTI does not provide ongoing operational support for ENGLP and as such, ENGLP does not receive a cost allocation from EDTI.

- Costs related to the development of standard operating procedures – ENGLP has identified the need to improve the documentation currently in place in relation to health, safety and environment related procedures and system integrity management. In a number of cases the current documentation is out of date or does not meet industry standard. Accordingly, ENGLP proposes to undertake to improve this documentation in 2020 and estimates the cost of this work to be $100,000.

144. As itemized in Table 4.3.3.5-2 below, the $925,014 of one-time costs ENGLP is proposing to recover in this Application are the costs required to develop standard operating procedures and the regulatory costs related to this Application and proceeding EB-2018-0235. The additional $188,336 in one-time costs related to Application EB-2016-0236 which was withdrawn subsequent to the Board's Decision and Order in Proceeding EB-2018-0235 and resolved all issues from NRG's original cost of service filing.[11] Although the application and evidence associated with EB-2016-0236 has provided significant value to ENGLP in its preparation of the historical information for this Application, ENGLP is not proposing to recover the costs related to that proceeding.

Table 4.3.3.5-2
Total One-time Costs Proposed for Recovery
($)

	One-time Cost Category	A **Amount proposed for recovery**
1	EB-2018-0235 - 2018 IRM and Associated filings	216,481
2	EB-2018-0336 - 2020 Cost of Service	608,533
3	Development of Standard Operating Procedures	100,000
4	**Total**	**925,014**

145. ENGLP is proposing to recover the $925,014 in one-time costs outlined in Table 4.3.3.5-2 above by amortizing these costs over the five-year period of this Application starting with the 2020 Test Year and the four subsequent years covered by the Price Cap IR

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[11] EB-2016-0236 Letter from the Board Dated December 14, 2018.

Term. Accordingly, ENGLP has included one-fifth of these costs, $185,003 in the regulatory costs included in Section 4.3.3.2 for the 2020 Test Year.

4.3.3.6 Low Income Programs

146. The Low-income Energy Assistance Plan ("LEAP") has been developed by the OEB to aid with payment of natural gas bills to eligible low-income ratepayers. In accordance with the Gas Distribution Access Rule ("GDAR"), the following is as provided in ENGLP's Conditions of Service applicable to customers of its Aylmer operations.

147. The program includes emergency financial assistance and the application of special customer service practices and standards for eligible low-income customers. To qualify for the program, customers must meet the income eligibility criteria as defined by the OEB. LEAP emergency financial assistance is administered through a social service agency, and ENGLP is partnered with the Branch of St. Thomas Salvation Army in administering the Low Income Energy Program Emergency Funding Assistance (LEAP EFA), which benefits customers in its franchise area.

148. Consistent with the OEB's requirement, ENGLP provides, each year, the greater of 0.12% of total distribution revenue or $2,000 to the fund. As such, ENGLP has calculated the 2020 LEAP EFA to be included in the revenue requirement as follows:

Table 4.3.3.6-1
LEAP EFA Calculation
($)

		A **2020 Test Year**
1	Distribution Revenue	6,652,600
2	Percentage Applied	0.12%
3	**LEAP Fund**	**7,983**

4.3.3.7 Charitable and Political Donations

149. ENGLP is not requesting for any recovery of charitable or political contributions in its revenue requirement other than funding for LEAP (Section 4.3.3.6).

150. ENGLP is allocated a portion of Community Relations costs from its Corporate Shared Services (Section 4.3.3.3). Consistent with the OEB rules, donations included in Community Relations costs have been excluded from the applied-for revenue requirement as reflected in Section 4.3.3.3.

4.4 Depreciation Expense

151. Given the size of the utility ENGLP has not undertaken a depreciation study for this Application and is relying on the depreciation study completed and filed by Union Gas in EB-2011-0210.

152. ENGLP cannot confirm the depreciation procedures or policies previously used by NRG for the Aylmer operation. ENGLP has included EPCOR's Depreciation Policy (FA-007) as Exhibit 4, Tab 3, Schedule 4 to be used by Aylmer. ENGLP notes that it is proposing to update the service lives of some of the assets as discussed further below.

153. Based on the limited information provided to ENGLP by NRG upon transition of the assets, ENGLP was not able to assess and further componentize any of historical assets if appropriate. All capital additions since the acquisition of the assets have been completed in accordance with EPCOR componentization practices, which break down capital additions into major parts and components in accordance with IFRS.

154. ENGLP forecasts a depreciation expense of $1.14 million for the 2020 Test Year. Table 4.4-1 below provides the details of ENGLP's depreciation expense for the historical, 2018 Forecast, 2019 Bridge Year and 2020 Test Year. ENGLP has included continuity schedules by asset group in Exhibit 2, Tab 1, Schedule 2.

Table 4.4-1
Summary of Depreciation Expense
($)

			A	B	C	D	E	F	G	H	I	J	K	L
	Asset Group	**Revised 2020 Test Year' Asset Description**	**2011 OEB Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2017 Stub**	**2018 F**	**2019 Bridge Year**	**2020 Test Year**
1	Land	Land	0	0	0	0	0	0	0	0	0	0	0	0
2	Buildings	Structures & Improvements - General Plant	14,699	15,148	15,148	15,187	15,260	15,260	15,260	15,532	3,883	15,532	15,876	14,327
3		Structures & Improvements – Distribution Plant												
4		Structures & Improvements – Transmission Plant												
5	Furniture & Fixtures	Furnishing / Office Equipment	4,466	4,669	5,350	5,549	7,010	7,430	7,596	7,596	1,903	7,596	7,596	5,359
6	Computer Equipment	Computer Equipment	5,967	6,054	5,250	5,824	5,908	9,151	12,490	13,778	12,066	64,017	46,013	63,185
7	Computer Software	Software - Acquired	8,245	14,172	12,128	11,204	10,828	10,858	52,232	56,892	11,889	46,895	62,176	59,386
8	Machinery & Equipment*	Tools and Work Equipment	301,048	173,586	180,449	182,750	189,007	149,158	18,931	18,419	4,210	18,399	19,255	51,303
9	Communication Equipment	Communications Equipment - Hardware	12,784	12,145	12,145	12,510	13,739	13,739	14,938	15,288	3,840	15,359	16,611	15,406
10	Automotive	Vehicles - Transportation Equipment	94,569	85,489	74,467	72,148	72,271	53,491	-34,196	36,238	5,965	31,633	45,089	53,344
11		Vehicle - Heavy Work Equipment												
12	Meters	Meters - Residential	77,346	78,807	81,476	86,856	96,283	100,403	232,366	231,145	34,519	97,548	108,841	148,558
13		Meters - Commercial												63,217
14		Meter - IGPC												2,357
15	Regulators	Regulators	42,453	46,138	47,681	50,300	51,118	51,651	54,202	54,457	13,614	56,270	67,532	5,375
16		Regulator and Meter Installations												
17		Measuring and Regulating Equipment												75,554
18	Plastic Mains	Mains - Plastic (Distribution Plant)	229,119	254,475	265,820	267,376	269,206	275,315	295,507	365,225	91,380	373,612	403,413	309,730
19	Steel Mains	Mains - Metallic (Distribution Plant)	0	0	0	0	0	0	0	0	0	0	0	0
20	Ethanol Pipeline - IGPC Project	Mains - Metallic (IGPC)	232,512	227,231	227,231	227,528	227,528	227,528	227,528	228,996	57,576	260,942	309,251	129,448
21	Plastic Services	Services - Plastic	87,518	96,844	103,475	111,777	113,475	115,358	118,179	122,095	30,764	126,871	132,033	101,894
22	Franchises and Consents	Franchises and Consents	89,359	97,130	39,399	44,091	25,921	33,330	34,806	36,217	9,150	37,120	37,646	37,646
23	**Sum**		**1,200,085**	**1,111,888**	**1,070,019**	**1,093,100**	**1,097,554**	**1,062,672**	**1,049,839**	**1,201,878**	**280,759**	**1,151,793**	**1,271,333**	**1,136,086**

*includes Rental Equipment in years prior to 2016

155. Table 4.4-2 below shows the historical depreciation rates for the utility as approved by the OEB in Decision EB-2010-0018 in 2011 and the rates used by ENGLP for 2018 Forecast, 2019 Bridge Year and the 2020 Test Year depreciation calculations. ENGLP confirms the depreciation rates used for 2018 and 2019 are based on the OEB approved rates for its predecessor, NRG. The proposed changes to the 2020 depreciations rates are discussed below.

Table 4.4-2
Depreciation Rates

		A	B	C	D	E
	Current Asset Description	**Proposed 2020 Test Year Asset Description**	**2011 OEB Approved**	**2018 F**	**2019 Bridge**	**2020 Proposed**
1	Land	Land	0.00%	0.00%	0.00%	0.00%
2	Buildings	Structures & Improvements - General Plant	2.22%	2.22%	2.22%	1.92%
3		Structures & Improvements – Distribution Plant				2.22%
4		Structures & Improvements – Transmission Plant				2.03%
5	Furniture & Fixtures	Furnishing / Office Equipment	6.75%	6.75%	6.75%	6.67%
6	Computer Hardware	Computer Equipment	33.33%	33.33%	33.33%	25.00%
7	Computer Software	Software - Acquired	20.00%	20.00%	20.00%	10.00%
8	Machinery & Equipment	Tools and Work Equipment	9.22%	9.22%	9.22%	6.67%
9	Communication Equipment	Communication Equipment	7.73%	7.73%	7.73%	6.67%
10	Automotive	Vehicles - Transportation Equipment	16.60%	16.60%	16.60%	16.60%
11		Vehicle - Heavy Work Equipment				6.92%
12	Meters	Meters - Residential	3.62%	3.62%	3.62%	10.00%
13		Meters - Commercial				5.00%
14		Meter – IGPC				16.67%
15	Regulators	Regulators	3.67%	3.67%	3.67%	5.00%
16		Regulator and Meter Installations				2.80%
17		Measuring and Regulating Equipment				3.66%
18	Plastic Mains	Mains - Plastic (Distribution Plant)	3.24%	3.24%	3.24%	2.31%
19	Steel Mains	Mains - Metallic (Distribution Plant)	13.45%	13.45%	13.45%	2.83%
20	Ethanol Pipeline - IGPC Project	Mains - Metallic IGPC (Transmission Plant)	5.00%	5.00%	5.00%	1.98%
21	Plastic Services	Plastic Service Lines (net of contributions)	3.33%	3.33%	3.33%	2.51%
22	Franchises and Consents	Franchises and Consents	4.80%	4.80%	4.80%	4.80%
23	Franchises – Aylmer & Appeal	Franchises – Aylmer & Appeal	5.00%	5.00%	5.00%	5.00%

156. ENGLP is proposing to update the depreciation rates for some of its assets used in the Aylmer operation for the 2020 Test Year. Following close of the acquisition of the assets from NRG in November 2017, ENGLP reviewed the existing depreciation rates as compared to other gas utilities. As a result of this review, ENGLP considered it prudent to adopt the Union Gas, now Enbridge, OEB-approved depreciation rates in EB-2011-0210[12] as ENGLP believes the

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[12] EB-2011-0210, Depreciation rates per Union Gas 2013 Rate Case Evidence, Exhibit D3, Tab 4, Schedule 1.).

depreciation rates approved for Enbridge are more reflective of the actual useful lives of the assets. The two exceptions to the adoption of Enbridge depreciation rates are Meters and Vehicles – Transportation Equipment. The rationale for each of these exceptions is provided below in the respective sections.

157. In addition to the depreciation rate change, ENGLP is proposing to revise its asset descriptions for the 2020 Test Year to reflect similar descriptions based on Union Gas' asset descriptions. Further, the change will ensure consistency with the OEB's prescribed uniform system of accounts for natural gas utilities.

158. The proposed changes to each asset group are discussed individually below.

Land

159. ENGLP is not proposing any changes to the land asset group.

Buildings

160. ENGLP is proposing to break down the building asset group into three categories and update the depreciation rate from the current 2.22%. The three categories and proposed depreciation rates are:

- Structures & Improvements - General Plant (1.92%)
- Structures & Improvements – Distribution Plant (2.22%, no change)
- Structures & Improvements – Transmission Plant (2.03%)

Furniture and Fixtures

161. ENGLP is proposing to change the asset group description to Furnishing and Office Equipment and change the depreciation rate from 6.75% to 6.67% to be consistent with other gas utilities.

Computer Hardware

162. ENGLP is proposing to change the asset group description to Computer Equipment and change the depreciation rate from 33.33% to 25.00%. The description and depreciation update will make ENGLP consistent with other gas utilities.

163. Prior to the 2020 Test Year, these assets were depreciated on a declining balance. ENGLP proposes to change the amortization method to straight line depreciation. This will be consistent with how assets in this category are treated amongst other EPCOR subsidiaries.

Computer Software

164. ENGLP is proposing to change the asset group description to Software – Acquired and change the depreciation rate from 20.00% to 10.00%. The description and depreciation update will ensure consistency with EPCOR’s depreciation policy.

165. Similar to Computer Hardware, these assets were depreciated on a declining balance. ENGLP proposes to change the amortization method to straight line depreciation for the 2020 Test Year. This will be a more simple calculation and also consistent how assets in this category are treated amongst other EPCOR subsidiaries.

Machinery & Equipment

166. ENGLP is proposing to change the asset group description to Tools and Work Equipment and change the depreciation rate from 9.22% to 6.67%. The description and depreciation update will make ENGLP consistent with other gas utilities.

167. Similar to Computer Hardware and Software, these assets were depreciated on a declining balance. ENGLP proposes to change the amortization method to straight line depreciation for the 2020 Test Year. This will be consistent with how assets in this category are treated amongst other EPCOR subsidiaries.

Communication Equipment

168. For this asset group, ENGLP is proposing to change the depreciation rate from 7.73% to 6.67%. The depreciation update will make ENGLP consistent with other gas utilities.

Automotive Equipment

169. ENGLP is proposing to componentize the automotive equipment group into the following two categories and proposed depreciation rates:

- Vehicles - Transportation Equipment (ENGLP) (16.60%, no change)
- Vehicle - Heavy Work Equipment (6.92%)

170. The depreciation rate for Vehicles – Transportation Equipment will remain unchanged at 16.60% as it best represents the useful life the utility has experienced for these assets. For Vehicle – Heavy Work Equipment, ENGLP is proposing a depreciation rate of 6.92% which is consistent with other gas utilities.

Meters - Residential Meters

171. ENGLP is proposing to change the depreciation rates for the residential meters asset class from 3.62% to 10% to reflect the seal life of ten years for a new residential meter (AC-250 meter). The AC-250 meters are used for lower volume customers including residential customers as well as lower volume commercial and industrial customers in Rate 1.

172. Historically, the useful life of a meter could be extended by prolonging the seal life through compliance sampling. However, commencing in 2011, Measurement Canada refined the rules for compliance sampling which limited the chances of successful sampling and shortened the lifespan of the refurbished meter. Combining this with increased costs of refurbishment and the decreased costs of new meters, the replacement of these meters became more economical than refurbishing the existing meters. Accordingly, ENGLP decided to discontinue sampling and refurbishment of the residential meters thereby changing the useful life of meters to the ten year seal life.

173. To implement the change in depreciation rate for AC-250 meters, commencing January 1, 2020 meters in-service will be depreciated over their remaining useful life, or a period of ten years minus the number of years in service at December 31, 2019. Any meters that have been in service for ten or more years will be disposed of, generating a forecasted loss on disposal of $162,461, equal to the remaining net book value of these meters in 2020.

174. ENGLP is proposing to establish a Disposition of Meters Deferral Account to record the amount of this loss in 2020 for recovery at a future date. This is discussed further in 9.3.2 of Exhibit 9, Tab 1, Schedule 1.

Meters – Commercial and IGPC Ethanol Inc.

175. ENGLP is proposing to change the depreciation rate for commercial meters from 3.62% to 5.00% as this reflects what ENGLP has experienced in the field. ENGLP is also proposing to change the depreciation rate of the IGPC meter from 3.62% to 16.67% as this specific meter for IGPC has a seal life of 6 years.

Regulators

176. ENGLP is proposing to componentize the regulators asset group into three distinct categories and update the depreciation rate as follows:

- Regulators (5.00% from 3.67%)
- Regulator and Meter Installations (2.80%)
- Measuring and Regulating Equipment (3.66%)

177. The description and depreciation update will make ENGLP consistent with other gas utilities.

Plastic Mains

178. ENGLP is proposing to change plastic mains asset group to Mains – Plastic (Distribution Plant) and update the depreciation rate from 3.24% to 2.31%. The description and depreciation update will make ENGLP consistent with other gas utilities.

Steel Mains

179. ENGLP is proposing to change steel mains asset group to Mains – Metallic (Distribution Plant) and update the depreciation rate from 13.45% to 2.83%. The description and depreciation update will make ENGLP consistent with other gas utilities.

Ethanol Pipeline – IGPC Project

180. ENGLP is proposing to change the asset group description to Mains – Metallic IGPC (Distribution Plant) and update the depreciation rate from 5.00% to 1.98%. The description and depreciation rate change will make ENGLP consistent with other gas utilities.

181. In addition to aligning the rates with those used by Union Gas, the change in depreciation rate for this asset class will result in a more stable rate base for Rate 6 over the 5 year period covered by the Application. The current depreciation rate of 5% depreciates the dedicated rate base for Rate 6 on an accelerated basis and beyond the forecasted capital spending in the 2019 Bridge Year and the 2020 Test Year. ENGLP expects limited spending related to this rate base over the Price Cap IR Term. Without adjusting the depreciation rate as proposed the rate base would reduce significantly in the four year period (2021-2024) following the 2020 Test Year; however, the customer's rate would not reflect this decrease until the revenue requirement is adjusted in the next rebasing application. Under a Price Cap IR methodology proposed in this Application in Exhibit 10, the change in depreciation rate as proposed by ENGLP is in the best interest of the customer. As noted in section 1.5.5 of Exhibit 1, Tab 1, Schedule 1 in order to protect ENGLP and its other ratepayers ENGLP is proposing the extension of the requirement for an Irrevocable Letter of Credit from the customer in Rate 6 for the net book value of the assets in the rate base for this rate class.

Plastic Services

182. ENGLP is proposing to change the asset group description to Services - Plastic and update the depreciation rate from 3.33% to 2.51%. The description and depreciation update will make ENGLP consistent with other gas utilities.

Franchises

183. ENGLP is not proposing any changes to the franchise asset group.

Depreciation Impact

184. ENGLP has calculated the impact of the change of the service lives in the 2020 Test Year in Table 4.4-3 below. The propose change will result in a $0.28 million decrease in depreciation expense. The decrease is driven primarily by the plastic mains and IGPC's pipeline.

Table 4.4-3
Depreciation Expense by Asset Group Net of Contributed Assets
($)

	Asset Group	**Revised Asset Group**	A **2020 Test Year (no change to rates)**	B **2020 Test Year (proposed)**
1	Land	Land	0	0
2	Buildings	Structures & Improvements - General Plant	16,564	14,327
3		Structures & Improvements – Distribution Plant		0
4		Structures & Improvements – Transmission Plant		0
5	Furniture & Fixtures	Furnishing / Office Equipment	5,359	5,359
6	Computer Equipment	Computer Equipment	35,677	63,185
7	Computer Software	Software - Acquired	77,001	59,386
8	Machinery & Equipment	Tools and Work Equipment	18,909	51,303
9	Communication Equipment	Communication Equipment	17,863	15,406
10	Automotive	Vehicles - Transportation Equipment	53,344	53,344
11		Vehicle - Heavy Work Equipment	0	0
12	Meters	Meters - Residential	53,778	148,558
13		Meters - Commercial	45,769	63,217
14		Meter – IGPC	512	2,357
15	Regulators - New	Regulators - New	3,945	5,375
16		Regulator and Meter Installations		0
17		Measuring and Regulating Equipment	75,753	75,554
18	Plastic Mains	Mains - Plastic (Distribution Plant)	434,420	309,730
19	Steel Mains	Mains - Metallic (Distribution Plant)	0	0
20	Ethanol Pipeline - IGPC Project	Mains - Metallic IGPC (Transmission Plant)	326,921	129,448
21	Plastic Services	Plastic Service Lines (net of contributions)	135,180	101,894
22	Franchises and Consents	Franchises and Consents	37,646	37,646
24	**Sum**		**1,338,642**	**1,136,086**

Asset Retirement Obligations

185. ENGLP does not have any asset retirement obligations (ARO).

4.5 Taxes

186. This section includes ENGLP's costs associated with property and income taxes that are included in the revenue requirement. Each component is described below.

Property Taxes

187. The forecast of property taxes 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. (i.e., aggregate assessed value of all pipeline assets).

188. The previous year average tax rate is adjusted for the forecasted increase and multiplied by the assessed market value to arrive at the forecast for property taxes.

189. The property tax amounts for the periods from 2011 to 2020 are set out in Table 4.5.1-1 below.

Table 4.5.1-1
Property Taxes Payable
($)

	A	B	C	D	E	F	G	H	I	J	K
Expense Category	**2011 OEB Approved**	**2011 A**	**2012 A**	**2013 A**	**2014 A**	**2015 A**	**2016 A**	**2017 A**	**2018 F**	**2019 Bridge Year**	**2020 Test Year**
1 Property Taxes	400,776	415,184	414,606	471,816	506,712	533,094	540,380	492,809	573,251	605,000	632,000

Note: Years 2011-2017 based on fiscal period from October to September. Years 2018 -2020 based on calendar period from January to December .

Income Taxes

190. ENGLP has included a copy of its 2017 partnership financial return in Exhibit 4, Tab 2, Schedule 1. ENGLP confirms that the 2017 financial statements included in this Application are the same 2017 financial statements filed with its 2017 partnership financial return.

191. ENGLP's effective tax rate is 26.5% for 2018 to 2020 based on a provincial tax rate of 11.5% and a federal tax rate of 15.0%. The tax rate is applied to the forecasted taxable income to arrive at the income tax payable. Forecasted taxable income is based on distribution revenue, less O&M, property taxes, interest expense and capital cost allowance. ENGLP's distribution revenue calculation can be found in Exhibit 3, Tab 1, Schedule 1 for 2018 and 2019 and in Table 6.1.1-2 of Exhibit 6, Tab 1, Schedule 1 for the 2020 Test Year. A summary of income taxes is presented in Table 4.5.2-1 below, reflecting the anticipated rates based on current data available.

Table 4.5.2-1
Income Taxes Payable
($)

		A	B	C
	Description	**2018 Forecast**	**2019 Bridge**	**2020 Test**
1	Commodity Revenue	**4,297,717**	**4,664,597**	**4,749,851**
2	less: Commodity Cost	(4,299,009)	(4,666,367)	(4,749,851)
3	Distribution Revenue	**7,234,872**	**7,079,005**	**6,652,600**
4	add: Other Revenue	119,793	112,913	112,913
5	less: Distribution OM&A and Transportation Cost (Deductible Portion)	(5,085,665)	(3,912,408)	(4,027,074)
6	less: Property Taxes	(573,251)	(605,000)	(632,000)
7	less: Interest Expense	(379,857)	(383,924)	(408,085)
8	less: CCA	(1,314,600)	(1,648,659)	(1,681,235)
9	**Taxable Income**	**0**	**640,157**	**17,119**
10	Income Taxes Payable			
11	Federal Income Tax @ 15%	0	96,024	2,568
12	Provincial Income Tax @ 11.5%	0	73,618	1,969
13	Income Tax Expense	**0**	**169,642**	**4,536**
14	**Effective Tax Rate**	**26.50%**	**26.50%**	**26.50%**

192. ENGLP notes that it cannot provide the historical income tax expense in the table above. Although ENGLP can report the income tax expense under NRG's ownership from its audited financial statements, ENGLP does not have access to the detailed financial records required to calculate the historical regulatory taxable income.

193. Table 4.5.2-2 below calculates ENGLP's capital cost allowance (CCA) continuity schedule for the 2018 to 2020 and reconciles to the CCA amounts in row 5 in the table above.

Table 4.5.2-2
CCA Continuity
($)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	CCA Class	**CCA Class Description**	**CCA Rate**	**2018 Opening UCC**	**2018 Additions**	**CCA Claimed**	**2018 Closing UCC**	**2019 Opening UCC**	**2019 Additions**	**CCA Claimed**	**2019 Closing UCC**	**2020 Opening UCC**	**2020 Additions**	**CCA Claimed**	**2020 Closing UCC**
1	Land	Land	0%	0	0	0	0	0	0	0	0	0	0	0	0
2	1	Building	4%	343,433	0	(12,082)	331,351	331,351	31,000	(13,874)	348,477	348,477	31,000	(14,559)	364,918
3	8	Furniture	20%	543,266	40,365	(99,111)	484,520	484,520	47,399	(101,644)	430,274	430,274	16,000	(87,655)	358,620
4	10	Computer Hardware	30%	51,018	107,041	(27,583)	130,476	130,476	108,000	(55,343)	183,133	183,133	47,000	(61,990)	168,143
5	12	Tools	100%	46,822	0	(41,180)	5,642	5,642	246,601	(128,942)	123,301	123,301	26,000	(136,301)	13,000
6	14.1	Goodwill	5%	3,965,201	21,055	(174,834)	3,811,422	3,811,422	0	(190,571)	3,620,851	3,620,851	0	(181,043)	3,439,808
7	50	Software	55%	130,306	0	(63,033)	67,273	67,273	20,000	(42,500)	44,773	44,773	10,000	(27,375)	27,398
8	51	Mains	6%	15,947,525	2,092,733	(896,776)	17,143,482	17,143,482	2,905,845	(1,115,784)	18,933,543	18,933,543	1,210,000	(1,172,313)	18,971,231
9			**Total**	**21,027,571**	**2,261,194**	**(1,314,600)**	**21,974,166**	**21,974,166**	**3,409,845**	**(1,648,659)**	**23,735,352**	**23,735,352**	**1,340,000**	**(1,681,235)**	**23,394,117**

4.6 Demand Side Management Costs

194. ENGLP is not requesting any approvals for Demand Side Management (DSM) funding for the 2020 Test Year. Also, ENGLP does not have any prior approvals for DSM funding.

Filed: 2019-01-31
EB-2018-0336
Exhibit 4
Tab 2
Schedule 1
Page 1 of 24

Canada Revenue Agency / Agence du revenu du Canada

Protected B when completed

Partnership Financial Return

T5013
Financial

055 For office use only

Full disclosure is required pertaining to all documents relating to this return. All the information requested in this form and in the documents supporting your information return is "prescribed information".

Complete this financial return using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*. You can file this return electronically without a Web access code using the "File a return" service in My Business Account at canada.ca/my-cra-business-account. Your authorized representative can access this service in Represent a Client at canada.ca/taxes-representatives.

Note: All legislative references provided on this form are from the *Income Tax Act*.

Identification

Partnership account number
001 74396 8299 RZ0001

Partnership name:
006 EPCOR Natural Gas Limited Partnership
007

Partnership operating or trading name:
008
009

Location of the partnership head office
Has this location changed since the last time you filed a partnership information return? **010** ☐ 1 Yes ☒ 2 No

If **Yes**, enter the address of the new location on lines 011 to 018:
011
012
City **015** Province/State **016**
Country **017** Postal or ZIP code **018**

Mailing address of the partnership (if different from the head office address)
Has this address changed since the last time you filed a partnership information return? **020** ☐ 1 Yes ☒ 2 No

If **Yes**, enter the new mailing address on lines 021 to 028:
021 c/o
023
024
City **025** Province/State **026**
Country **027** Postal or ZIP code **028**

Location of the partnership's books and records
(if different from the head office address)
Has this location changed since the last time you filed a partnership information return? **030** ☐ 1 Yes ☒ 2 No

If **Yes**, enter the address of the new location on lines 031 to 038:
031
032
City **035** Province/State **036**
Country **037** Postal or ZIP code **038**

Is this an amended return? **040** ☐ 1 Yes ☒ 2 No

Fiscal period to which this information return applies:
Fiscal period start **060** Year Month Day From 2017-01-01
Fiscal period end * **061** Year Month Day to 2017-12-31
* If you answer **Yes** to question 078 below, enter the date when the partnership ceased to exist.

062 The end members of this partnership are (tick the applicable boxes):
01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? **070** ☐ 1 Yes ☒ 2 No
If **Yes**, enter the date the partnership was created: Year Month Day **071**

Number of T5013 slips: **073** 2

Is this the partnership's final information return up to dissolution? **078** ☐ 1 Yes ☒ 2 No

If an election was made under section 261 by one or more partners, state the functional currency code used for this return: **079**

Was the partnership a Canadian partnership throughout the fiscal period? **082** ☒ 1 Yes ☐ 2 No

086 Type of partnership at the end of the fiscal period

Non tax shelter	**Tax shelter (TS)**
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number: **087**

Industry code (NAICS): **098** 221210

Approval code: RC-17-P006

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001	**Partnership account number** 74396 8299 RZ0001	**061**	**Fiscal period end** Year Month Day 2017-12-31

Documents required to be attached to this T5013 FIN, *Partnership Financial Return*

1. The T5013 Summary, *Summary of Partnership Income*, and a copy of the T5013, *Statement of Partnership Income*, issued to partners and nominees or agents.

2. The GIFI schedules; 100, 125, 140 (when more than one schedule 125 is filed), and schedule 141 which is not required for investment clubs.

3. Schedule 1 (if you are an inactive partnership, see line 280 in the guide for more information) and Schedule 50.

4. Answer all of the following questions. For each **Yes** response, **attach** the schedule to the partnership return, unless otherwise instructed.

				Schedule or form
At any time during the fiscal period, was the partnership a member (directly, or indirectly through one or more partnerships) of another partnership?	**150**	☐ 1 Yes	☒ 2 No	9
Has the partnership had any transactions, including sections 97 and 98, and subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents.	**162**	☐ 1 Yes	☒ 2 No	T2058, T2059, and/or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐ 1 Yes	☒ 2 No	T106
Is the partnership required to file Form T1134 in respect of any foreign affiliates in the fiscal period?	**172**	☐ 1 Yes	☒ 2 No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property, gifts of medicine, or federal, provincial, territorial, or municipal political contributions?	**202**	☐ 1 Yes	☒ 2 No	2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☒ 1 Yes	☐ 2 No	5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ 1 Yes	☒ 2 No	6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ 1 Yes	☐ 2 No	8
Does the partnership have any resource-related deductions (excluding renounced expenditures)?	**212**	☐ 1 Yes	☒ 2 No	12
Is the partnership allocating any investment tax credits (ITCs)? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	**231**	☐ 1 Yes	☒ 2 No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	**232**	☐ 1 Yes	☒ 2 No	T661
Did the partnership allocate renounced resource expenses to its members?	**252**	☐ 1 Yes	☒ 2 No	52
Did the partnership own or hold specified foreign property where the total cost amount of all such property, at any time in the fiscal period, was more than CAN$100,000?	**259**	☐ 1 Yes	☒ 2 No	T1135

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001 **Partnership account number**	74396 8299 RZ0001
061 **Fiscal period end** Year Month Day	2017-12-31

Additional information

Did the partnership use the international financial reporting standards (IFRS) when it prepared its financial statements?	**270**	☒ 1 Yes	☐ 2 No
Was a slip issued to one or more nominees or agents?	**271**	☐ 1 Yes	☒ 2 No
Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2?	**272**	☐ 1 Yes	☒ 2 No
Does the partnership have one or more new nominees or agents?	**273**	☐ 1 Yes	☒ 2 No
Did the partnership allocate any amount of income tax deducted at source?	**274**	☐ 1 Yes	☒ 2 No
Did the partnership make any other election(s) under the Act during the fiscal period? If **Yes**, attach a copy of each election form to this return.	**275**	☐ 1 Yes	☒ 2 No
Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed? If **Yes**, provide the business number(s) of the predecessor partnership(s):	**277**	☐ 1 Yes	☒ 2 No

278 ______

279 ______

Was the partnership inactive throughout the fiscal period this information return applies to? If **Yes**, see the guide to verify your filing requirements.	**280**	☐ 1 Yes	☒ 2 No
Did members of the partnership immigrate to Canada during the fiscal period?	**291**	☐ 1 Yes	☒ 2 No
Did members of the partnership emigrate from Canada during the fiscal period?	**292**	☐ 1 Yes	☒ 2 No
If the major business activity is construction, did you have any subcontractors during the fiscal period?	**295**	☐ 1 Yes	☒ 2 No
Did the partnership report its farming or fishing income using the cash method?	**296**	☐ 1 Yes	☒ 2 No
Is this a publicly traded partnership?	**297**	☐ 1 Yes	☒ 2 No
If **Yes**, did the partnership issue T5008 information slips to report transactions of interests in the partnership?	**298**	☐ 1 Yes	☐ 2 No

Miscellaneous information

Was an NR4 information return for tax deductions withheld at source filed for the fiscal period?	**301**	☐ 1 Yes	☒ 2 No
If **Yes**, provide the non-resident account number:	**302**		
If **Yes** to 301, were NR4 slips issued?	**303**	☐ 1 Yes	☐ 2 No
Is this partnership a specified investment flow-through (SIFT) partnership?	**304**	☐ 1 Yes	☒ 2 No
If **Yes**, enter the taxable non-portfolio earnings for the fiscal period:	**305**		
If **Yes**, enter the tax payable under Part IX.1 for the fiscal period:	**306**		
Enter the amount of the late filing penalty from line 307 of Schedule 52.	**307**		
Amount of payment enclosed with this return:	**308**		

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001 **Partnership account number** 74396 8299 RZ0001

Fiscal period end
061 Year Month Day 2017-12-31

Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15) of the Act

400 Name of designated partner
402 Identification number

Additional information for tax shelters only

Principal promoter

500 Last name (print)
501 First name (print)
502 Identification number

Certification

I, **950** Koski **951** Jacyn **954** Corporate Controller

Last name (print) First name (print) Position or title

certify that the information given on this form is correct and complete. I further certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as specifically disclosed in a statement attached to this return.

955 2018-05-15 Year Month Day
Signature of the authorized partner
956 (780) 412-4481 Telephone number

Language of correspondence

Indicate your language of correspondence: **990** ☒ 1 English ☐ 2 French

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source canada.ca/cra-info-source, personal information bank(s) CRA PPU 224.

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Canada Revenue Agency | Agence du revenu du Canada

Financial Statement Notes Checklist

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T5013
Schedule 141

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	☒ Original ☐ Amended
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31	

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- For more information, see Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*, and Guide RC4088, *General Index of Financial Information (GIFI).*
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, *Partnership Financial Return.*

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected with the partnership? * . . . . **097** 1 Yes ☒ 2 No ☐

Note: If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.

* A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the accountant's highest level of involvement: **198**

Completed an auditor's report . . . . 1 ☐

Completed a review engagement report . . . . 2 ☐

Conducted a compilation engagement . . . . 3 ☐

Part 3 – Reservations

If you selected option 1 or option 2 **in part 2** above, answer the following question:

Has the accountant expressed a reservation? . . . . **099** 1 Yes ☐ 2 No ☐

Part 4 – Other information (continued on page 2)

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: **110**

Prepared the information return (financial statements prepared by client) . . . . 1 ☐

Prepared the information return and the financial information contained therein (financial statements have not been prepared) . . . . 2 ☐

Were notes to the financial statements prepared? . . . . **101** 1 Yes ☒ 2 No ☐

If **yes***,* answer the following four questions:

Are subsequent events mentioned in the notes? . . . . **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . **106** 1 Yes ☐ 2 No ☒

Is information regarding commitments mentioned in the notes? . . . . **107** 1 Yes ☒ 2 No ☐

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below . . . . **108** 1 Yes ☐ 2 No ☒

Are you filing joint venture(s) financial statements? . . . . **109** 1 Yes ☐ 2 No ☐

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Partnership account number	Fiscal period end Year Month Day
74396 8299 RZ0001	2017-12-31

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In other comprehensive income Increase (decrease)
Property, plant and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the partnership apply hedge accounting during the fiscal period? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the partnership discontinue hedge accounting during the fiscal period? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31

Is this a NIL schedule? . . . . **999** Yes ☐ No ☒

Assets – lines 1000 to 2599

1000	2,408,209.00	**1060**	2,220,554.00	**1120**	82,234.00
1310	1.00	**1311**	999.00	**1484**	356,929.00
1599	5,068,926.00	**1600**	41,810.00	**1740**	17,815,259.00
2008	17,857,069.00	**2010**	3,093,372.00	**2178**	3,093,372.00
2599	26,019,367.00				

Liabilities – lines 2600 to 3499

2620	1,153,515.00	**2860**	3,154,113.00	**2960**	111,064.00
3139	4,418,692.00	**3220**	13,088.00	**3300**	8,660,000.00
3450	8,673,088.00	**3499**	13,091,780.00		

Partner's capital – lines 3540 to 3575

3545	-431,969.00	**3550**	-431,969.00	**3551**	1.00
3552	-432.00	**3554**	13,359.00	**3560**	12,928.00
3561	999.00	**3562**	-431,537.00	**3564**	13,345,197.00
3571	12,914,659.00	**3575**	12,927,587.00	**3585**	26,019,367.00

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SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	3,216,905.00	**8089**	3,216,905.00	**8299**	3,216,905.00

Cost of sales – lines 8300 to 8519

8320	1,498,346.00	**8370**	52,528.00	**8518**	1,550,874.00
8519	1,666,031.00				

Operating expenses – lines 8520 to 9369

8570	15,484.00	**8670**	174,078.00	**8710**	24,238.00
8760	100,326.00	**9060**	218,090.00	**9284**	1,565,784.00
9367	2,098,000.00	**9368**	3,648,874.00	**9369**	-431,969.00

Farming revenue – lines 9370 to 9659

9659	0.00

Farming expenses – lines 9660 to 9899

9898	0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	-431,969.00	**9999**	-431,969.00

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Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Protected B when completed

T5013
Schedule 1

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Is this a NIL schedule? 999 ☐ Yes ☒ No

(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140			500		-431,969.00
Add:					
Provision for Part IX.1 specified investment flow through (SIFT) taxes	101				
Amortization/depreciation of tangible assets	104	174,078.00			
Amortization of natural resource assets	105				
Amortization of intangible assets	106	15,484.00			
Recapture of capital cost allowance from Schedule 8	107				
Income or loss for tax purposes from partnerships	109				
Loss in equity of affiliates	110				
Loss on disposal of assets per financial statements	111				
Charitable donations and gifts from Schedule 2	112				
Political contributions from Schedule 2	114				
Current fiscal period's holdbacks	115				
Deferred and prepaid expenses	116				
Depreciation in inventory – end of fiscal period	117				
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	118				
Capitalized interest and property taxes on vacant land	119				
Non-deductible club dues and fees	120				
Non-deductible meals and entertainment expenses	121	257.00			
Non-deductible automobile expenses	122				
Non-deductible life insurance premiums	123				
Non-deductible company pension plans	124				
Reserves from financial statements – balance at the end of the fiscal period	126				
Soft costs on construction and renovation of buildings	127				
Salaries and wages paid to partners deducted on financial statements	150				
Cost of products available for sale that were consumed	151				
Personal expenses of the partners paid by the partnership	152				
Dividend rental arrangement compensation payment deductions	154				
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	155				
Certain fines and penalties	156				
Amount from line 508 on page 2 of this schedule	199	1,112,679.00			
Total (**Add** lines 101 to 199. Enter this amount on line 501)		1,302,498.00 ▶	501	+	1,302,498.00
Deduct: Amount from line 511 on page 3 of this schedule			502	–	720,695.71
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	=	149,833.29
Deduct: Net income (loss) for general partners			504	–	149.84
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	=	149,683.45

Approval code: RC-17-P006

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Partnership account number	**Fiscal period end** Year Month Day
74396 8299 RZ0001	2017-12-31

Add:

Accounts payable and accruals for cash basis – closing	201				
Accounts receivable and prepaid for cash basis – opening	202				
Accrual inventory – opening	203				
Accrued dividends – prior fiscal period	204				
Book loss on joint ventures or partnerships	205				
Capital items expensed	206	1,007,771.00			
Debt issue expense	208				
Deemed dividend income	209				
Deemed interest on loans to non-residents	210				
Deemed interest received	211				
Development expenses claimed in current fiscal period	212				
Dividend stop-loss adjustment	213				
Dividends credited to the investment account	214				
Exploration expenses claimed in current fiscal period	215				
Financing fees deducted in books	216				
Foreign accrual property income	217				
Foreign affiliate property income	218				
Foreign exchange included in retained earnings	219				
Gain on settlement of debt – income inclusion under subsection 80(13)	220				
Interest paid on income debentures	221				
Limited partnership losses	222				
Loss from international banking centres	223				
Mandatory inventory adjustment – included in current fiscal period	224				
Non-deductible advertising	226				
Non-deductible interest	227				
Non-deductible legal and accounting fees	228				
Optional value of inventory – included in current fiscal period	229				
Other expenses from financial statements	230				
Recapture of SR&ED expenditures from Form T661	231				
Resource amounts deducted	232				
Sales tax assessments	234				
Write-down of capital property	236				
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237				
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238				
Taxable/Non-deductible other comprehensive income items	239				
Total (**Add** lines 201 to 239. Enter this amount on line 506)		1,007,771.00	506	+	1,007,771.00

Other additions:

600	Incentive plan overaccrual current year	290	2,956.00			
601	Income inclusion as per s22 election	291	96,234.00			
602	Provision deducted for doubtful accounts	292	5,718.00			
603		293				
604		294				
	Total (**Add** lines 290 to 294. Enter this amount on line 507)		104,908.00	507	+	104,908.00

Total (**Add** lines 506 and 507) 508 = 1,112,679.00
Enter the amount from line 508 on line 199 on page 1 of this schedule.

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Partnership account number	**Fiscal period end** Year Month Day
74396 8299 RZ0001	2017-12-31

Deduct:

Accounts payable and accruals for cash basis – opening	300			
Accounts receivable and prepaid for cash basis – closing	301			
Accrual inventory – closing	302			
Accrued dividends – current fiscal period	303			
Bad debt	304			
Book income of joint venture or partnership	305			
Equity in income from affiliates	306			
Exempt income under section 81	307			
Income from international banking centres	308			
Mandatory inventory adjustment – included in prior fiscal period	309			
Contributions to a qualifying environmental trust	310			
Non-Canadian advertising expenses – broadcasting	311			
Non-Canadian advertising expenses – printed materials	312			
Optional value of inventory – included in prior fiscal period	313			
Other income from financial statements	314			
Payments made for allocations in proportion to borrowing and bonus interest payments	315			
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316			
Non-taxable/Deductible other comprehensive income items	347			

Other less common deductions:

700		390		
701		391		
702		392		
703		393		
704		394		

Total (**Add** lines 300 to 394. Enter this amount on line 509) ▶ **509** +

Other deductions:

Gain on disposal of assets per financial statements	401			
Non-taxable dividends under section 83	402			
Capital cost allowance from Schedule 8	403	720,695.71		
Terminal loss from Schedule 8	404			
Foreign non-business tax deduction under subsection 20(12)	407			
Prior fiscal period's holdbacks	408			
Deferred and prepaid expenses	409			
Depreciation in inventory – end of prior fiscal period	410			
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411			
Reserves from financial statements – balance at the beginning of the fiscal period	414			
Patronage dividends	416			
Contributions to deferred income plans	417			
Total (**Add** lines 401 to 417. Enter this amount on line 510)		720,695.71	▶ **510**	+ 720,695.71

Total (**Add** lines 509 and 510) **511** = 720,695.71

Enter this amount on line 502 on page 1 of this schedule.

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Canada Revenue Agency Agence du revenu du Canada

Protected B when completed

Allocation of Salaries and Wages, and Gross Revenue for Multiple Jurisdictions

T5013
Schedule 5

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31	☒ Original ☐ Amended

- Fill out this schedule if, during the fiscal period, the partnership had permanent establishments in more than one jurisdiction.
- All the information requested in this form and in the documents supporting your information return is "prescribed information."
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 5.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Part 1 – Allocation of salaries and wages, and gross revenue

Jurisdiction		Yes	No		Salaries and Wages		Gross Revenue
Newfoundland and Labrador	003	☐	☒	100		200	
Newfoundland and Labrador – offshore	004	☐	☒	101		201	
Prince Edward Island	005	☐	☒	102		202	
Nova Scotia	007	☐	☒	103		203	
Nova Scotia – offshore	008	☐	☒	104		204	
New Brunswick	009	☐	☒	105		205	
Quebec	011	☐	☒	106		206	
Ontario	013	☒	☐	107	207,911.00	207	3,216,905.00
Manitoba	015	☐	☒	108		208	
Saskatchewan	017	☐	☒	109		209	
Alberta	019	☒	☐	110	22,691.00	210	
British Columbia	021	☐	☒	111		211	
Yukon	023	☐	☒	112		212	
Northwest Territories	025	☐	☒	113		213	
Nunavut	026	☐	☒	114		214	
Outside Canada	027	☐	☒	115		215	
			Totals	130	230,602.00	280	3,216,905.00

Part 2 – Amounts allocated by one or more partnerships

If the partnership held an interest in one or more partnerships, provide the following information:

	300 Other partnership name	350 Other partnership account number	400 Were any amounts reported in Part 1 above allocated to you from this other partnership? Yes	No
1			☐	☐
2			☐	☐
3			☐	☐
4			☐	☐
5			☐	☐
6			☐	☐

See the privacy notice on your return.

Approval code: RC-17-P006

Canada

Canada Revenue Agency   Agence du revenu du Canada

Capital Cost Allowance (CCA)

Protected B when completed

T5013
Schedule 8

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
EPCOR Natural Gas Limited Partnership	74396 8299 RZ0001	2017-12-31	☒ Original ☐ Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, and to account for acquisitions and/or dispositions of depreciable property.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 8.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

	200 (1) Class number	**201** (2) Undepreciated capital cost (UCC) at the beginning of the fiscal period (UCC at the end of the previous fiscal period (column (13) of Schedule 8))	**203** (3) Cost of acquisitions during the fiscal period (new property must be available for use) *	**205** (4) Net adjustments (show negative amounts in brackets) **	**207** (5) Proceeds of dispositions during the fiscal period (amount not to exceed the capital cost)	(6) UCC (column (2) **plus** column (3) **plus** or **minus** column (4) **minus** column (5))	**211** (7) 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column (5)) ***	(8) Reduced UCC (column (6) **minus** column (7))	**212** (9) CCA rate (%)	**213** (10) Recapture of CCA	**215** (11) Terminal loss	**217** (12) CCA (column (8) **multiplied** by column (9), **or** a lower amount) ****	**220** (13) UCC at the end of the fiscal period (column (6) **minus** column (12))
1	1		350,442.00			350,442.00	175,221.00	175,221.00	4.00			7,008.84	343,433.16
2	8		603,629.00			603,629.00	301,814.50	301,814.50	20.00			60,362.90	543,266.10
3	10		60,021.00			60,021.00	30,010.50	30,010.50	30.00			9,003.15	51,017.85
4	50		179,733.00			179,733.00	89,866.50	89,866.50	55.00			49,426.58	130,306.42
5	51		16,440,747.00			16,440,747.00	8,220,373.50	8,220,373.50	6.00			493,222.41	15,947,524.59
6	12		46,822.00			46,822.00	23,411.00	23,411.00	100.00				46,822.00
7	14.1		4,066,873.00			4,066,873.00	2,033,436.50	2,033,436.50	5.00			101,671.83	3,965,201.17
8													
9													
10													
			21,748,267.00			21,748,267.00	10,874,133.50	10,874,133.50	Totals	**230**	**240**	**250** 720,695.71	21,027,571.29

Enter the amount on line 230 on line 107 of Schedule 1.
Enter the amount on line 240 on line 404 of Schedule 1.
Enter the amount on line 250 on line 403 of Schedule 1.

* Include any property acquired in previous fiscal periods that has now become available for use. This property would have been previously excluded from column (3). List separately any acquisitions that are not subject to the 50% rule; see the *Income Tax Regulations* 1100(2) and (2.2).

** Include amounts applicable to depreciable assets transferred under section 85. See Guide T4068 for examples of adjustments to include in column (4).

*** The net cost of acquisitions is the cost of acquisitions column (3) plus or minus certain adjustments from column (4). For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the fiscal period is shorter than 365 days, prorate the CCA claim except for some classes. For more information, see Guide T4068.

Approval code: RC-17-P006

See the privacy notice on your return.

T5013 SCH 8 E (16)

Canadä

Canada Revenue Agency Agence du revenu du Canada

Partner's Ownership and Account Activity

Protected B when completed

T5013
Schedule 50

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
EPCOR Natural Gas Limited Partnership	743968299RZ0001	2017-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	**010**	2
Number of partners who disposed of all, or part of, their partnership interest	**011**	
Number of nominees or agents	**012**	
Total of all amounts from line 220	**015**	149,833.29

Partner 1

Ownership						Fiscal period's income (loss) allocation	Account activity
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
EPCOR Ontario Utilities Inc.	744116096RC0001	2	2	0.1000	☐ Yes ☒ No	149.84	1.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
13,359.00							

Partner 2

Ownership						Fiscal period's income (loss) allocation	Account activity
100	**101**	**105**	**106**	**107**	**110**	**220**	**300**
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
EPCOR Power Development Corporation	877148627RC0005	2	0	99.9000	☐ Yes ☒ No	149,683.45	999.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	**320**	**330**	**340**	**350**	**410**	**420**	**430**
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
13,345,197.00					149,683.45		

Approval code: RC-17-P006

T5013 SCH 50 E (17)

Canada

Protected B when completed

Partner 3	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 4	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

Canada Revenue Agency Agence du revenu du Canada

Fiscal period end
Exercice se terminant le
YYYY MM DD / AAAA MM JJ: 2017-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant
EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé: **002** 2
Country code / Code du pays: **003** CAN
Recipient type / Genre de bénéficiaire: **004** 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): **001** 743968299RZ0001
Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: **010**
Total business income (loss) / Total du revenu (de la perte) d'entreprise: **020** 149 84

Partner's identification number / Numéro d'identification de l'associé: **006** 744116096RC0001
Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: **005** 0.100003
Total capital gains (losses) / Total des gains (pertes) en capital: **030**
Capital cost allowance / Déduction pour amortissement: **040** 720 72

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales
▶ EPCOR Ontario Utilities Inc.
27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116	ON	142 47	116	AB	7 37
118	ON	3,058 74	118	AB	158 27

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

For Tax Centre 1
Pour le Centre fiscal 1

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le: YYYY MM DD / AAAA MM JJ 2017-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 0	003: CAN	004: 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): 001 743968299RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: 010 149,683 45

Total business income (loss) / Total du revenu (de la perte) d'entreprise: 020

Partner's identification number / Numéro d'identification de l'associé: 006 877148627RC0005

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: 005 99.899997

Total capital gains (losses) / Total des gains (pertes) en capital: 030

Capital cost allowance / Déduction pour amortissement: 040 719,974 99

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales

► EPCOR Power Development Corporation

27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant		Box Case	Code	Amount – Montant	
104	ON	142,319	17	104	AB	7,364	28
105		13,495,879	45	106		13,495,879	45
118	ON	3,055,577	75	118	AB	158,110	24

Box – Case	Code	Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

For Tax Centre 1
Pour le Centre fiscal 1

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency　Agence du revenu du Canada

Fiscal period end / Exercice se terminant le
YYYY MM DD / AAAA MM JJ
2017-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002 2	**003** CAN	**004** 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001 743968299RZ0001	**010**	**020** 149 84

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006 744116096RC0001	**005** 0.100003	**030**	**040** 720 72

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées)　First name – Prénom　Initials – Initiales

► EPCOR Ontario Utilities Inc.

27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116	ON	142 47	116	AB	7 37
118	ON	3,058 74	118	AB	158 27

Box – Case	Code	Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Attach to your income tax return 2
Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2

See recipient instructions
Voir les instructions du bénéficiaire

T5013 (15)　**Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le: YYYY MM DD 2017-12-31 AAAA MM JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé **002**	2
Country code / Code du pays **003**	CAN
Recipient type / Genre de bénéficiaire **004**	3
Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) **001**	743968299RZ0001
Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire **010**	
Total business income (loss) / Total du revenu (de la perte) d'entreprise **020**	149 84
Partner's identification number / Numéro d'identification de l'associé **006**	744116096RC0001
Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes **005**	0.100003
Total capital gains (losses) / Total des gains (pertes) en capital **030**	
Capital cost allowance / Déduction pour amortissement **040**	720 72

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

► EPCOR Ontario Utilities Inc.

27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box – Case	Code	Other information – Autres renseignements	Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
			116	ON	142 47	116	AB	7 37
			118	ON	3,058 74	118	AB	158 27

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For Recipient – Keep this slip for your records 3
Bénéficiaire – Conservez pour vos dossiers 3

See recipient instructions
Voir les instructions du bénéficiaire

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le — YYYY MM DD / AAAA MM JJ: 2017-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé — **002** 0

Country code / Code du pays — **003** CAN

Recipient type / Genre de bénéficiaire — **004** 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) — **001** 743968299RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire — **010** 149,683 45

Total business income (loss) / Total du revenu (de la perte) d'entreprise — **020**

Partner's identification number / Numéro d'identification de l'associé — **006** 877148627RC0005

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes — **005** 99.899997

Total capital gains (losses) / Total des gains (pertes) en capital — **030**

Capital cost allowance / Déduction pour amortissement — **040** 719,974 99

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées)   First name – Prénom   Initials – Initiales

► EPCOR Power Development Corporation

27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box – Case	Code	Other information – Autres renseignements	Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
			104	ON	142,319 17	104	AB	7,364 28
			105		13,495,879 45	106		13,495,879 45
			118	ON	3,055,577 75	118	AB	158,110 24

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Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Attach to your income tax return 2
Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2

See recipient instructions
Voir les instructions du bénéficiaire

T5013 (15)   **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency
Agence du revenu du Canada

Filed: 2019-01-31
EB-2018-0336
Exhibit 4
Tab 2
Schedule 1
Page 21 of 24

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Fiscal period end – Exercice se terminant le (YYYY MM DD – AAAA MM JJ): 2017-12-31

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *) – Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code Code de l'associé	**002**	0
Country code Code du pays	**003**	CAN
Recipient type Genre de bénéficiaire	**004**	3
Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	**001**	743968299RZ0001
Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	**010**	149,683 45
Total business income (loss) Total du revenu (de la perte) d'entreprise	**020**	
Partner's identification number Numéro d'identification de l'associé	**006**	877148627RC0005
Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	**005**	99.899997
Total capital gains (losses) Total des gains (pertes) en capital	**030**	
Capital cost allowance Déduction pour amortissement	**040**	719,974 99

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► EPCOR Power Development Corporation
27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104	ON	142,319 17	104	AB	7,364 28
105		13,495,879 45	106		13,495,879 45
118	ON	3,055,577 75	118	AB	158,110 24

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Keep this slip for your records 3
Bénéficiaire – Conservez pour vos dossiers 3

See recipient instructions
Voir les instructions du bénéficiaire

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency — Agence du revenu du Canada

Fiscal period end
Exercice se terminant le

YYYY MM DD
2017-12-31
AAAA MM JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 2	**003** CAN	**004** 3

Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) Total du revenu (de la perte) d'entreprise
001 743968299RZ0001	**010**	**020** 149 84

Partner's identification number Numéro d'identification de l'associé	Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	Total capital gains (losses) Total des gains (pertes) en capital	Capital cost allowance Déduction pour amortissement
006 744116096RC0001	**005** 0.100003	**030**	**040** 720 72

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

► EPCOR Ontario Utilities Inc.
27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116	ON	142 47	116	AB	7 37
118	ON	3,058 74	118	AB	158 27

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period end / Exercice se terminant le (YYYY MM DD / AAAA MM JJ): 2017-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

EPCOR Natural Gas Limited Partnership
2000 10423 101 Street NW
Edmonton AB T5H 0E8

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Box	Description	Value
002	Partner code / Code de l'associé	0
003	Country code / Code du pays	CAN
004	Recipient type / Genre de bénéficiaire	3
001	Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	743968299RZ0001
010	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	149,683 45
020	Total business income (loss) / Total du revenu (de la perte) d'entreprise	
006	Partner's identification number / Numéro d'identification de l'associé	877148627RC0005
005	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	99.899997
030	Total capital gains (losses) / Total des gains (pertes) en capital	
040	Capital cost allowance / Déduction pour amortissement	719,974 99

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► EPCOR Power Development Corporation

27th Floor, Taxation Department
2000 - 10423 101 Street NW
Edmonton AB T5H 0E8

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104	ON	142,319 17	104	AB	7,364 28
105		13,495,879 45	106		13,495,879 45
118	ON	3,055,577 75	118	AB	158,110 24

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency / Agence du revenu du Canada

Summary of Partnership Income
Sommaire des revenus d'une société de personnes

Protected B / Protégé B when completed / une fois rempli

T5013 Summary / Sommaire

Fill out this summary and related slips using the instructions in guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.

Remplissez ce sommaire et les feuillets connexes en suivant les instructions du guide T4068, *Guide pour la déclaration de renseignements des sociétés de personnes (formulaires T5013)*.

Do not use this area. N'inscrivez rien ici.

50 ☐☐☐☐ 1616

For the fiscal period – Pour l'exercice

Start / Début 2017-01-01 (Year Month Day / Année Mois Jour)

End / Fin 2017-12-31 (Year Month Day / Année Mois Jour)

Partnership's account number / Numéro de compte de la société de personnes 74396 8299 RZ0001

Name of the partnership – Nom de la société de personnes EPCOR Natural Gas Limited Partnership

Postal or ZIP code / Code postal ou ZIP T5H 0E8

Are you a nominee or agent? (tick if yes and provide the following information)
Êtes-vous un mandataire ou un agent? (cochez si oui et fournir les renseignements qui suivent) ☐

Name of the nominee or agent – Nom du mandataire ou de l'agent

Postal or ZIP code / Code postal ou ZIP

Nominee or agent's account number / Numéro de compte du mandataire ou de l'agent

Is the partnership a tax shelter? (tick if yes)
La société de personnes est-elle un abri fiscal? (cochez si oui) ☐

If yes, provide the tax shelter identification number
Si oui, fournir le numéro d'identification de l'abri fiscal

Totals from T5013 slips – Totaux des feuillets T5013

Total number of T5013 information slips attached:
Nombre total de feuillets de renseignements T5013 joints : **009** 2

Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire	**010**	149,683	45
Total business income (loss) – Total du revenu (de la perte) d'entreprise	**020**	149	84
Total capital gains (losses) – Total des gains (pertes) en capital	**030**		
Capital cost allowance – Déduction pour amortissement	**040**	720,695	71

Complete the six generic boxes identified below taken from the T5013 slips – Remplissez les lignes ci-dessous pour les six cases génériques qui parviennent des feuillets T5013

Canadian and foreign net rental income (loss) – Revenu net (perte nette) de location canadien et étranger	**110**		
Professional income (loss) – Revenu (perte) de profession libérale	**120**		
Renounced Canadian exploration expenses – Frais renoncés d'exploration au Canada	**190**		
Renounced Canadian development expenses – Frais renoncés d'aménagement au Canada	**191**		
Expenses qualifying for an ITC – Frais admissibles aux fins du CII	**194**		
Total carrying charges – Total des frais financiers	**210**		

Person to contact about this return / Personne-ressource que nous pouvons contacter à propos de cette déclaration
076 Jordan Schneider

Area code / Indicatif régional – Telephone number / Numéro de téléphone
078 (780) 412-3723

Extension / Numéro de poste

Certification – Attestation

I certify that the information given in this return and related summary and slips is correct and complete.

J'atteste que les renseignements fournis dans cette déclaration de renseignements et sur tous les feuillets connexes sont exacts et complets.

Date: 2018-05-15

Signature of authorized person – Signature d'une personne autorisée

Position or office – Poste ou titre: Corporate Controller

Prepared by – Preparé par: Jordan Schneider

Date: 2018-05-15

Personal information, including the social insurance number, is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank(s) CRA PPU 224.

Les renseignements personnels sont recueillis selon la *Loi de l'impôt sur le revenu* afin d'administrer les programmes fiscaux, de prestations et autres. Ils peuvent également être utilisés pour toute fin liée à l'application ou à l'exécution de la *Loi* telle que la vérification, l'observation et le recouvrement des sommes dues à l'État. Les renseignements peuvent être transmis à une autre institution gouvernementale fédérale, provinciale ou territoriale, ou vérifiés auprès de celles-ci, dans la mesure où la loi l'autorise. Cependant, le défaut de fournir ces renseignements pourrait entraîner des intérêts à payer, des pénalités ou d'autres mesures. Les particuliers ont le droit, selon la *Loi sur la protection des renseignements personnels*, d'accéder à leurs renseignements personnels et de demander une modification, s'il y a des erreurs ou omissions. Consultez Info Source en allant à **www.arc.gc.ca/gncy/tp/nfsrc/nfsrc-fra.html** et le(s) Fichier(s) de renseignements personnels ARC PPU 224.

Canada

SERVICE LEVEL AGREEMENT

THIS AGREEMENT made effective as of ENTER EFFECTIVE DATE (the "**Effective Date**").

BETWEEN:

SELECT SERVICE PROVIDER NAME.**,** a corporation formed under the laws of the Province of Alberta, (hereinafter referred to as the "**Service Provider**" or "SELECT SERVICE PROVIDER ABBREVIATION.")

- and -

EPCOR Natural Gas Limited Partnership, a corporation formed under the laws of the Province of Ontario (hereinafter referred to as the "**Service Receiver**")

WHEREAS the Service Receiver has requested the Service Provider to provide, and the Service Provider is willing to provide the Contract Services (as hereinafter defined) to the Service Receiver upon the terms and conditions set forth in this Agreement.

AND WHEREAS the Service Provider, the Service Receiver, or both, have created a compliance plan to describe the systems, policies and mechanisms that such party intends to use to ensure that all of its officers, employees, agents and contractors comply with the *Affiliate Relationship Code for Gas Utilities* as established by the Ontario Energy Board as it may be amended from time to time.

AND WHEREAS such compliance plan is intended to concurrently comply with the requirements of the *Affiliate Relationship Code for Gas Utilities* which require that a services agreement be executed between the Parties to support the regulatory process.

NOW THEREFORE THIS AGREEMENT EVIDENCES that in consideration of the mutual covenants and agreements contained in this Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties do hereby covenant and agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, including all recitals, schedules and attachments hereto, unless otherwise indicated or the context otherwise requires, the following words and expressions shall have the following meanings:

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

*"***Affiliate***" means an affiliate as defined in section 3 of the Act;*

"**Agreement**" means this agreement and all schedules and addenda attached hereto;

"**ARC**" means the *Affiliate Relationships Code for Gas Utilities*

"**Board**" means the Ontario Energy Board

"**Board of Arbitrators**" shall have the meaning ascribed to that term in Section 8.3;

"**Business Day**" means any day except a Saturday, Sunday or statutory holiday in the Province of Alberta or Ontario;

"**Canadian Prime Rate**" means the rate of interest expressed as a rate per annum which the Royal Bank of Canada establishes from time to time at its main office in Edmonton, Alberta as its posted prime rate;

"**Conduct Requirements**" means the requirements outlined in the ARC, and the requirements contained in the associated compliance plan;

"**Contract Services**" means, collectively, the services more particularly described in Schedule "A" to this Agreement;

"**Force Majeure**" shall have the meaning ascribed to that term in Section 7.2;

"**Indemnified Party**" shall have the meaning ascribed to that term in Section 4.1;

"**Indemnifying Party**" shall have the meaning ascribed to that term in Section 4.1;

"**Information**" shall have the meaning ascribed to that term in Section 6.1;

"**Party**" or "**Parties**" means a Party or Parties to this Agreement; and

"**Person**" means an individual, corporation, partnership, joint venture, association, trust or unincorporated organization.

"**Term**" shall have the meaning ascribed to that term in Section 5.1.

1.2 Number and Gender

Words used herein importing the singular number only shall include the plural and vice versa and words importing the use of any gender shall include all genders.

1.3 References

References to the words “Article” and “Section” herein shall, unless the contrary be expressly stated, refer to an Article or Section of this Agreement, and references to “hereof", “herein", “hereby”, “hereunder” and “this Agreement” refer to the whole of this Agreement including the Schedules and Addendum attached hereto.

1.4 Amendments to Agreements and Law

References herein to any agreement or document shall be deemed to be a reference to such agreement or document as varied, amended, modified, supplemented, or replaced from time to time. Any specific reference herein to any enactment of law shall be deemed to be such enactment as the same may be amended or re-enacted from time to time and every statute that may be substituted therefore and, in any such event reference to such enactment shall be read as referring to such enactment as so amended, re-enacted or the statute substituted therefore, as the case may be.

1.5 Headings

The division of this Agreement into Articles, Sections and other subdivisions, the provision of a table of contents and the insertion of headings are for convenience of reference only and are not to be used in construing or interpreting this Agreement or any portion thereof.

1.6 Governing Law

This Agreement shall be governed by and interpreted in accordance with the laws of the Province of Alberta and the federal laws of Canada applicable therein.

1.7 Severability

Each provision of this Agreement is intended to be severable and, if any provision is determined by a court of competent jurisdiction to be illegal or invalid or unenforceable for any reason whatsoever, such provision shall be severed from this Agreement and will not affect the legality or validity or enforceability of the remainder of this Agreement or any other provision hereof.

1.8 Next Business Day

In the event that any date on which any action is required to be taken hereunder by any of the Parties hereto is not a Business Day, such action shall be required to be taken on the next succeeding day which is a Business Day.

1.9 Entire Agreement

This Agreement including the annexed Schedules constitutes the entire agreement among the Parties relating to the matters set forth herein and in the Schedules and shall supersede and cancel any and all pre-existing agreements and understandings among the Parties relating thereto. Any and all prior contemporaneous negotiations, prior memoranda of understanding or position, and preliminary drafts and prior versions of this Agreement or the Schedules, whether signed or unsigned, shall not be used to construe the terms or affect the validity or interpretation of this Agreement or the Schedules.

1.10 Schedules

The following Schedules are attached to and form part of this Agreement:

- Schedule “A” – Contract Services for Services Rendered ENTER BEGIN DATE – ENTER END DATE
- Schedule “B” – Basis of Payment for Contract Services for Services Rendered ENTER BEGIN DATE – ENTER END DATE

If there is any conflict between the body of this Agreement and the attached Schedules, the body of this Agreement shall prevail.

ARTICLE 2
CONTRACT SERVICES

2.1 Contract Services

Commencing on the Effective Date, the Service Provider shall provide to the Service Receiver the Contract Services more particularly described in Schedule "A" in accordance with this Agreement.

2.2 Warranty

The Service Provider represents and warrants that it is capable of providing the Contract Services as required by this Agreement. The Service Provider further represents and warrants that the Contract Services provided by the Service Provider pursuant to this Agreement will be performed with reasonable skill, care, and diligence and in accordance with generally accepted, utility operating standards and practices.

2.3 Laws and Regulation

The Service Provider shall comply with all laws and regulations governing the Service Receiver and the Service Provider which are applicable to the performance of the Contract Services at the place or places at which the Contract Services are performed, including, but not limited to the Conduct Requirements. The Service Provider confirms that it has been provided with full disclosure of the Service Provider's obligations under the ARC

2.4 Policies

The Service Provider shall comply with all applicable policies and procedures established by the Service Receiver from time to time including, without limitation, the Service Receiver's compliance plan, Privacy Policy, Alcohol and Drug Policy, Ethics Policy and any health, safety and security policies (the "**Policies and Procedures**"). The Service Provider confirms that it has been provided with full disclosure of all the Service Receiver's applicable Policies and Procedures.

2.5 Services

The parties acknowledge that this Agreement shall be subject to any rule application to the Service Provider made by the Ontario Energy Board pursuant to the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sched. B., s. 44, including without limitation, the *Affiliate Relationships Code for Gas Utilities* (the "Code"), as amended from time to time. Specifically, without limited the generality of the foregoing, the Service Receiver agrees to comply promptly with all requests either made or authorized by the Ontario Energy Board for information with respect to the services provided pursuant to this Agreement. This Agreement shall also be subject to any valid, applicable federal, provincial or other governmental regulatory body or authority having jurisdiction over a party or the subject matter of this Agreement.

ARTICLE 3
PAYMENT

3.1 Compensation

As full consideration for performance of the Contract Services, the Service Receiver shall pay the Service Provider the compensation ("**Compensation**") provided in Schedule "B" at the times and in the manner provided in Section 3.2. All fees payable to the Service Provider are exclusive of the federal goods and services tax and, if applicable, provincial sales taxes and harmonized sales tax but are inclusive of all other taxes, customs, duties, excise taxes and non-resident withholding taxes (if applicable).

3.2 Invoicing and Payment

The Service Provider shall invoice the Service Receiver each month, no later than the thirtieth (30th) calendar day of the following month. The appropriate manager within the Service Receiver shall review, and if appropriate, approve and forward the invoice to Accounts

Payable within thirty (30) days of receipt. Accounts payable shall enter the invoice into Oracle and each invoice shall be paid on the next available payment run.

3.3 Method of Payment

Each invoice shall be paid in full in Canadian funds by Electronic Funds Transfer (EFT) from the Service Receiver to the Service provider. Direct charges shall be handled in accordance with the Service Receiver's standard accounting policies and practices.

3.4 Invoice or Charge Errors

If an error is found in any invoice or record of direct charge, the Party identifying the error shall immediately advise the other Party. Any adjustment necessary to correct such error shall be made as soon as practical or, in the case of an error in a direct charge, in accordance with the Service Receiver's standard accounting policies and practices.

3.5 Records

The Service Provider shall maintain complete and accurate books, records, and accounts of and supporting documents for all work performed and items billed for Contract Services. The Service Provider shall ensure that the books, records, accounts, and documents are not destroyed without the Service Receiver's written authorization for a period of seven (7) years after the termination or expiration of this Agreement. The Service Provider shall, on demand, make available to the Service Receiver or its respective duly authorized representatives for inspection, reproduction, and audit or any other reasonable purposes, every such book, record, account, and document.

3.6 Invoice or Charge Disputes

In the event that the Manager within the Service Receiver disputes in good faith any part of a monthly invoice, such dispute shall be resolved, in accordance with the provisions of Article 8. If, after following the provisions of Article 8, it is determined that the invoice ought to be paid by the Service Receiver, the Service Receiver shall pay to the Service Provider the amount owing under the disputed invoice within fifteen (15) days of the date of such final determination.

ARTICLE 4
INDEMNITIES AND LIMITATION OF LIABILITY

4.1 Indemnity

Each Party (the "**Indemnifying Party**") shall indemnify, defend and save harmless the other Party (the "**Indemnified Party**") from and against any and all losses, claims, damages, liabilities or expenses (including legal expenses on a solicitor and his own client basis) suffered or incurred by the Indemnified Party as a result of, arising out of, or in connection with, the gross negligence or willful misconduct of the Indemnifying Party in the performance, purported performance, or non-performance of this Agreement, or the Indemnifying Party's breach of this Agreement, except to the extent caused by the gross negligence or will-full misconduct of the Indemnified Party or to the extent that any such act or omission was done or omitted pursuant to the specific instructions of the Indemnified Party.

4.2 Limitation of Liability for Consequential Damages

Notwithstanding anything to the contrary contained in this Agreement, neither Party will be liable to the other Party for any damage, cost, expense, injury, loss or other liability of an indirect, special or consequential nature suffered by the other Party or claimed by any third party against the other Party which arises due to such Party's failure to perform its obligations under this Agreement or for any other reason (including negligence on its part or on the part of any person for whose acts it is responsible), howsoever and when-so-ever caused, and whether arising in contract, negligence or other tort liability, strict liability or otherwise. Without limiting the generality of the foregoing, damage, injury or loss of an indirect or consequential nature shall include loss of revenue, loss of profits, loss of production, loss of earnings, loss of contract, cost of purchased or replacement capacity and energy, cost of capital and loss of the use of any facilities or property owned, operated, leased or used by the other Party or a third party.

ARTICLE 5
TERM

5.1 Term

This Agreement shall commence on the Effective Date and shall continue in full force until ENTER TERM END unless otherwise agreed to by the Parties in writing.

ARTICLE 6
CONFIDENTIALITY

6.1 Confidentiality

Subject to Section 6.2, each Party shall keep confidential and shall not:

(a) use, except for the purpose of performing its obligations or exercising its rights under this Agreement; or

(b) disclose, except as contemplated or permitted in this Agreement;

any confidential information (including without limitation Confidential Information as defined in the ARC), trade secret or confidential financial, technical, scientific, business or other confidential or proprietary information or document of the other Party or its Affiliates received by it or any of its Affiliates in the course of, or as a result of, the relationship established between the Parties pursuant to this Agreement (herein referred to collectively as the "**Information**").

6.2 Exceptions

A Party shall be entitled to disclose any Information to the extent:

(a) such Information is or becomes generally known to the public other than through a breach of this Agreement or any other obligation of confidentiality between the Parties;

(b) such Information is lawfully obtained by that Party from a third party or parties without breach of this Agreement or any other obligation of confidentiality between the Parties, as shown by documentation sufficient to establish the third party as the source of such Information and to the knowledge of the disclosing Party, without such disclosure constituting a breach by such third party or parties of an obligation of confidentiality;

(c) such Information is comprised of technical Information and was known to the disclosing Party prior to receipt thereof from the other Party, as shown by documentation sufficient to establish such knowledge;

(d) such Information was developed by the receiving Party independently of the disclosures made by the disclosing Party under this Agreement;

(e) such disclosure is required in connection with any regulatory, legal or administrative proceeding; provided that where circumstances permit prior to disclosure, the disclosing Party shall notify the other Party in writing of such proposed disclosure and at the other Party's request (and expense) apply for appropriate court or other orders to preserve the confidentiality of such Information;

(f) that such disclosure is required by law or by order of any governmental body having competent authority; provided that where the circumstances permit prior to disclosure (other than any disclosure required by applicable securities laws) the disclosing Party shall notify the other Party in writing of any such proposed disclosure and shall at the other Party's request (and expense) apply for appropriate court or other orders to preserve the confidentiality of such Information; and

(g) the other Party shall have provided its prior written approval for such disclosure by the disclosing Party.

ARTICLE 7
FORCE MAJEURE

7.1 Relief from Obligations

Subject to Section 7.3, if by reason of Force Majeure either Party to this Agreement is unable, wholly or partially, to perform or comply with its covenants and obligations hereunder, then the Party so affected by Force Majeure shall be relieved of liability and shall suffer no prejudice for failing to perform or comply during the continuance and to the extent of the inability so caused from and after the happening of the event of Force Majeure; provided that the Party invoking Force Majeure gives to the other Party prompt notice, written or oral (but if oral, promptly confirmed in writing) of such inability and reasonably full particulars of the cause thereof. If notice is not promptly given then the Party suffering the Force Majeure shall only be relieved from such performance or compliance from and after the giving of such notice. The Party invoking Force Majeure shall use all reasonable efforts to remedy the situation and remove, so far as possible and with reasonable dispatch, the cause of its inability to perform or comply; provided, however, that settlement of strikes, lockouts and other industrial disturbances shall be wholly within the discretion of the Party involved. The Party invoking Force Majeure shall give prompt notice of the cessation of the event of Force Majeure. Nothing in this Article 7 shall relieve a Party of its obligations to make payments when due hereunder.

7.2 Force Majeure

For the purposes of this Agreement, force majeure ("**Force Majeure**") shall mean any event beyond the reasonable control of the Party invoking Force Majeure, including therein but without restricting the generality thereof:

(a) lightning, storms, earthquakes, landslides, floods, washouts, and other Acts of God;

(b) fires, explosions, ruptures, breakage of or accidents to pipelines, plants, machinery, equipment or storage facilities;

(c) strikes, lockouts, or other labour disturbances;

(d) civil disturbances, sabotage, war, blockades, insurrections, vandalism, riots, epidemics;

(e) acts of terrorism;

(f) arrests and restraints by governments or governmental agencies;

(g) the order of any court;

(h) inability to obtain or curtailment of supplies of feed stocks or of electric power, water, fuel or other necessary utilities or services to operate any facilities or of any materials or equipment; or

(i) inability to obtain or revocation or amendment of any permit, authorization or approval of any governmental authority required to perform or comply with any obligation under this Agreement, unless the revocation or modification of any such necessary permit, authorization or approval was caused by the violation of the terms thereof or consented to by the party holding the same.

7.3 Exclusions from Relief

No Party shall be entitled to the benefits of the provisions of this Article 7 under any of the following circumstances:

(a) if the failure to perform or comply with any of the covenants or obligations herein imposed upon it was caused by arrest or restraint by governments or governmental agencies or the order of any court and such arrest, restraint or order was the result of a breach by the Party claiming suspension of the term of a permit, license, certificate or other authorization granted by a governmental or regulatory body having jurisdiction or of any applicable laws, regulations or orders;

(b) if the failure to perform or comply with any of the covenants or obligations herein imposed upon it was caused by the Party invoking Force Majeure having failed to use all reasonable efforts to remedy the situation and remove, so far as possible and with reasonable dispatch, the cause of its inability to perform or comply with such covenants or obligations; or

(c) if the failure to perform or comply with any of the covenants or obligations herein imposed upon it was caused by lack of funds or other financial cause for whatever reason.

ARTICLE 8
DISPUTE RESOLUTION

8.1 Dispute Resolution

Any matter in dispute under or relating to this Agreement, unless settled in the manner provided by Section 8.2, will be finally resolved by binding arbitration in the manner provided in Article 8.

8.2 Arbitration

All disputes arising out of or in connection with this Contract, or in respect of any legal relationship associated with or derived from this Contract, will be finally resolved by arbitration under the Arbitration Rules (the "Rules") of the ADR Institute of Canada, Inc. (the "Institute"), with the following exceptions:

- the arbitrator, and not the Institute, will administer the arbitration on an *ad hoc* basis;
- the Seat of Arbitration (as such term is defined in the Rules) will be Edmonton, Alberta;
- the location of the arbitration will be in Edmonton, Alberta; and
- the language of the arbitration will be conducted in English.

8.3 Continuing Obligations

The supply and purchase of Contract Services and payment therefore under this Agreement shall continue during the dispute resolution proceedings contemplated by this Article 8.

ARTICLE 9
NOTICE

9.1 Notice

Any notice, consent, request or other communication to be given in connection with this Agreement shall be in writing and shall be given by:

(a) personal delivery or registered mail, postage prepaid, to the following address for the recipient; or

(b) facsimile transmission to the following facsimile number (confirmed by a copy delivered by personal delivery to the following address) for the recipient;

addressed to the recipient as follows:

To Service Provider:
Select Service Provider's Name
Enter Service Provider's Address.
To Service Receiver:
EPCOR Natural Gas Limited Partnership
Enter Service Receiver's Address.

or to such other address, facsimile number or individual for notice as may then have been designated by the respective Party pursuant to Section 9.2. Any communication given to a Party as aforesaid shall be deemed to have been given at the time and upon the date of the receipt at the address of such Party.

9.2 Change of Address

Any Party may, from time to time, change its address, facsimile number or individual for notice by a notice given to the other Party in accordance with Section 9.1.

ARTICLE 10
GENERAL

10.1 Time of Essence

Time shall be of the essence in this Agreement and of all of its terms.

10.2 Further Assurance

The Parties shall with reasonable diligence perform all acts, execute and deliver all documents and instruments, do all such things and provide all such reasonable assurances as may be necessary or desirable to give effect to the provisions of this Agreement.

10.3 Amendments or Waiver

This Agreement may not be amended except by written instrument signed by all of the Parties hereto. No indulgence or forbearance by any Party hereunder shall be deemed to constitute a waiver of its rights to insist on performance in full and in a timely manner of all covenants of each of the other Parties hereunder and any such waiver, in order to be binding upon a Party, must be express and in writing and signed by such Party, and then such waiver shall be effective only in the specific instance and for the purpose for which it is given. No waiver of any term, condition or covenant by any Party shall be deemed to be a waiver by such Party of its rights to require full and timely compliance with the same term, condition or covenant thereafter, or with any other term, covenant or condition of this Agreement at any time.

10.4 No Discharge on Termination

Any provision of this Agreement under which an obligation of one Party hereto has accrued but has not been discharged shall not be affected by termination of this Agreement, nor shall the Party liable to perform be discharged as a result of any such termination, nor shall termination prejudice any right of one Party against the other in respect of anything done or omitted hereunder prior to such termination or in respect of any right to damages or other remedies.

10.5 Enurement

This Agreement shall enure to the benefit of and be binding upon the Service Provider and the Service Receiver and their respective successors and permitted assigns.

10.6 Assignment

This Agreement shall be assignable by either Party as necessary in connection with any bona fide financings, financing leases, reorganizations and mergers, but this Agreement shall not otherwise be assigned by either Party without the prior written consent of the other Party, which consent each of the Parties covenants not to unreasonably withhold. Notwithstanding any permitted assignment, the assignor shall continue to remain liable for the performance of obligations under this Agreement unless such assignor is released therefrom by instrument in writing signed by the other Party.

10.7 Counterparts

This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original but all of which when taken together shall constitute one and the same agreement.

10.8 Compliance Representations

Service Provider and Service Receiver represent to each other for the purpose of the ARC that each Party intends to comply with the Conduct Requirements and that this Agreement does comply with all Conduct Requirements.

10.9 Termination on Sale

In the event of the sale of the Service Provider to an unrelated Person who is not an Affiliate, the Service Receiver may unilaterally terminate this Agreement on 90 days' notice without penalty. Any termination notice must be given to the Service Provider a minimum of 90 days prior to the closing date of the sale. The Parties must, after the receipt of the termination notice from the Service Receiver to the Service Provider, negotiate transitional costs and additional resources required during the termination period in good faith, but any failure of the Parties to come to an agreement on these aforementioned costs and resources will not affect the Compensation payable to the Service Provider for the Contract Services provided up to the termination date.

IN WITNESS WHEREOF this Agreement has been duly executed by the Parties hereto under their respective corporate seals attested by the signatures of their respective officers duly authorized in that behalf effective as of the day and year first above written.

Select Service Provider Name.

Per: ______________________________

Enter Name of Signing Authority.
Enter Title.

EPCOR Natural Gas Limited Partnership, by its general partner, EPCOR Ontario Utilities Inc.

Per: ______________________________

Enter Name of Signing Authority.
Enter Title.

CERTIFICATION

The undersigned, being EPCOR Ontario Utilities Inc.’s Senior Vice-President, Commercial Services, Steve Stanley hereby certifies for and on behalf of EPCOR Natural Gas Limited Partnership (ENGLP), as general partner of ENGLP, that ENGLP’s costs, including the costs set out in ENGLP’s application filed January ____, 2019, are in compliance with the Ontario Energy Board’s *Affiliate Relationships Code for Gas Utilities*.

DATED this ____ day of January, 2019.

[original signed by]

Stephen Stanley

Senior Vice-President, Commercial Services
EPCOR Ontario Utilities Inc.

EPCOR UTILITIES INC.

Procurement Policy

January 01, 2019

Table of Contents

1.0 DEFINITIONS

1.1 **Accounts Payable (AP)** means the EPCOR Utilities Inc. group responsible for processing of all invoices and payments to suppliers for services or goods rendered.

1.2 **Blanket Purchase Agreement** Blanket Purchase Agreement is an agreement with suppliers for specific goods or services where pricing and quality have been identified for a pre-determined period of time. These agreements can be accessed by the BU through the self-serve process where they can order the release of these goods or services with the creation of a Blanket Release.

1.3 **Blanket Release** means the Oracle generated purchase document.

1.4 **Budgeted Foreign Exchange Rate** means the exchange rate to convert foreign currencies to Canadian dollars as approved by the Board in the annual budget.

1.5 **Business Unit or BU** means a business unit of EPCOR.

1.6 **CESAP** means the Contract Execution and Spending Authority Policy of EPCOR.

1.7 **Commit** means the commitment of EPCOR to a third party for the procurement of goods and/or services.

1.8 **Competitive Bidding** is a procurement method, in which bids are invited from contractors, suppliers and/or vendors for goods and/or services to certain scope, specifications and terms and conditions. The principle goal of a competitive bid is to use competition to capture best value while mitigating risk to EPCOR.

1.9 **Contract(s)** means any written document that legally binds EPCOR, including but not limited to agreements, amending agreements, change orders, letter agreements, letters of intent and/or memorandums of understanding, purchase orders, executed or to be executed by one or more Employees on behalf of EPCOR evidencing that EPCOR Utilities Inc., or a specific Legal Entity, and one or more third parties have exchanged legally binding rights, duties, obligations or promises for consideration.

1.10 **Draw Down Purchase Order** means a type of Purchase Order in Oracle which utilizes a $1 unit price; may be used in the situations described in Section 5.1.1 (iv) and (v).

1.11 **Emergency** means a situation requiring immediate action by an Employee for the protection of the environment, health and safety of Employees and/or the public or to prevent serious material harm or damage to EPCOR assets or prevent significant interruptions in the provision of services where the appropriate authorizations cannot be obtained before the immediate action must be taken.

1.12 **Employee(s)** means all employees and Corporate Officers of EPCOR.

1.13 **EPCOR** means any one or all of EPCOR Utilities Inc. and its direct and indirect Canadian subsidiaries, as applicable.

1.14 **EUI** means EPCOR Utilities Inc.

1.15 **Legal** means EUI’s Legal Department and external lawyers when directed by EUI’s Legal Department.

1.16 **Legal Entity** means the Canadian incorporated direct and indirect subsidiaries of EPCOR.

1.17 **Oracle** means EPCOR's Enterprise Resource Planning (ERP) system where the Purchasing module resides.

1.18 **Master Contract** means any Contract other than an International Swaps and Derivatives Association agreement wherein there is no set commitment or obligation on behalf of EPCOR to incur or procure a good or service from a third party but a causal relationship is established in preparation for and facilitation of same.

1.19 **Policy** means this Procurement Policy, as amended from time to time.

1.20 **Procurement Approval** means the approval of a purchase after the approval of a requisition by the appropriate BU.

1.21 **Procurement Approval Group** means a Procurement Employee's Commit limit as set out in Schedule "A" hereto.

1.22 **Purchase Order** means written authorization for a supplier to provide a good and/or service at a specified price, which becomes a legally binding contract once issued to the supplier.

1.23 **Procurement** means the Procurement organization operating within each EPCOR line of business responsible for the acquisition of goods, services, construction and facilities on behalf of the Business Units. This responsibility includes maintaining and administering the Procurement Policy, developing sourcing strategies, providing expert advice on procurement and contracting best practices, managing and overseeing purchasing activities, negotiation of contracts, and supplier relationship management.

1.24 **Regulator** means a third party organization or agreement that places obligations on EPCOR impacting EPCOR's procurement sourcing methods. Examples of such organizations or agreements include but are not limited to municipalities, Governments, Alberta's Electric System Operator (AESO), agreements with municipalities, trade agreements.

1.25 **Self-Serve** means the process for the creation of Blanket Releases against Blanket Purchase Agreements.

1.26 **SVP** means Senior Vice President.

1.27 **Standard Form Contracts** means those contracts set out in Appendix "A" of EPCOR's Legal Contract Review Procedure located on Legal's intranet site.

1.28 **Value Added Taxes** means all Goods and Services Tax, Provincial sales taxes, any State or Federal taxes, import/export taxes or duties.

2.0 INTRODUCTION AND PURPOSE

2.1 This Policy applies to all Employees of EPCOR.

2.2 The purpose of the Policy is to set out clear lines of accountability and control over the procurement of goods and/or services for EPCOR.

2.3 All amounts set out in this Policy are maximum limits, expressed in Canadian dollars (or the equivalent in any other currency or currencies at the applicable Budgeted Foreign Exchange Rate approved in the annual budget) exclusive of all Value Added Taxes.

3.0 GUIDING PRINCIPLES

3.1 EPCOR has adopted the following set of guiding principles that assist in the overall understanding of the procurement of goods and/or services. These guiding principles also ensure that high standards of practice are maintained.

3.1.1 EPCOR will maintain high legal, ethical, and professional standards in the procurement of goods and/or services.

3.1.2 Whenever possible, EPCOR will use fair and open competitive procurement processes; and

3.1.3 EPCOR will ensure that no one supplier shall be intentionally given an advantage over another in the procurement process. All suppliers shall be given the same opportunity to participate in EPCOR's procurement process to the extent they can provide the goods and/or services to the required specifications and/or requirements.

4.0 APPLICATION

4.1 Applicability

4.1.1 This Policy supersedes all existing Procurement Policies related to the procurement of goods and/or services at EPCOR.

4.1.2 This Policy applies to all Employees of EPCOR and to all procurement activity carried out by EPCOR, except as provided in 4.1.3.

4.1.3 This Policy does not apply to intercompany transactions between EUI and its subsidiaries.

5.0 ORDERING METHODS

5.1 EPCOR uses the following ordering methods to procure goods and/or services: Purchase Orders, Procurement Cards, Self-Serve (Blanket Releases), Supply Arrangements and non-Purchase Order invoices.

5.1.1 Purchase Orders

A Purchase Order is EPCOR's commitment to a supplier to procure goods and/or services and is a legally binding contract. Purchase Orders are also used by EPCOR to match orders, for receipt of goods and invoices in order to ensure that we pay only for the quantity of goods and services that we ordered and received and at the agreed upon amounts specified in the Purchase Order. The following controls must be adhered to when utilizing a Purchase Order:

i. A purchase requisition approved in accordance with CESAP is required to create a Purchase Order. The purchase requisition is the means to obtain approval of the expenditure whereas the Purchase Order is the means to commit EPCOR to the purchase of goods and/or services.

ii. Purchase Orders are to be issued for an annual period only.

iii. Renewals against multi-year Contracts will be done on a new PO each year unless the PO is for a project specific period where it may cover more than one fiscal year.

iv. If unit prices are known, a Drawdown Purchase Order may only be utilized for Purchase Orders that are for: (A) less than $400,000, or (B) $400,000 or greater where the relevant business unit or shared service Senior Vice-President has approved use of a Drawdown Purchase Order as evidenced by a signed exception form. Purchase Orders must not be split in order to bring values below the $400,000 threshold referred to in this paragraph.

v. If unit prices are known, for circumstances referred to in paragraph (iv)(A) above, use of a Purchase Order using unit prices and estimated quantities is strongly encouraged instead of a Drawdown Purchase Order unless the purchase involves one or more of the following:

- annual supply of the same or similar services from the same supplier;
- frequent, but not regularly scheduled, multiple deliveries to the same locations;
- future delivery schedule is unknown;
- precise volumes or quantities are not known until delivery, but there is a standard known price list and/or there is an approved Master Contract;
- delivery, packing charges, or supplier discounts and/or fees regularly affect final prices.

5.1.2 Procurement Card (P-Card)

Low risk, low dollar value items for EPCOR can be made by Employees without involving Procurement pursuant to EPCOR’s Procurement Card Policy.

5.1.3 Self-Serve (Blanket Releases)

Self-Serve is the generation of Blanket Releases against approved Blanket Purchase Agreements. This process is completed by Business Unit or supply chain employees and the request does not go through the Procurement organization. Oracle auto generates the Purchase Order (against an agreement that is already in place) and dispatches the order to the supplier.

Approval of the Blanket Release is as per the spend approval limits identified in the CESAP policy.

5.1.4 Supply Arrangements

Supply Arrangements are Blanket Agreements or Master Agreements in place at EPCOR for specific goods and/or services.

Employees are to purchase from Supply Arrangements to the greatest extent practical.

5.1.5 Non-Purchase Order Invoice

Refer to the Non-purchase Order Invoice Policy on Finance’s intranet site for details on when it is appropriate to use Non-Purchase Order invoices.

6.0 NON-COMPETITIVE PROCUREMENTS

6.1 In response to an Emergency, a Business Unit may procure goods and/or services, exercising prudence and judgment in the quantity, scope and duration of the goods and/or services procured. In Emergency situations, a competitive procurement process is not required.

All incidents where an Employee has acquired goods and/or services due to an Emergency are to be:

- Documented. Documentation is to include order date, total cost, supplier name, product and/or services description and emergency particulars, and
- Communicated as soon as practicable after the Emergency to the Employee's supervisor, the Business Unit's Senior Manager responsible for Procurement, Business Unit controller and the Corporate Controller.

6.2 For non-competitive procurements $75,000.00 or greater, the BU is to provide defensible justification (in writing) to Procurement, to support the procurement. The non-competitive procurement shall also be approved by the appropriate Approval Group (as identified in Schedule A of CESAP) that is one level higher than the Approval Group authorized to approve the Requisition.

7.0 APPROVALS AND LIMITS

7.1 Authority to Commit EPCOR to the procurement of goods and/or services is set out herein. Such authority however, may be subject to further limitations from time to time, to meet special business purposes, or other circumstances.

7.2 All Employees procuring goods and/or services in accordance with the limits set out herein are only authorized to execute or approve on behalf of the EPCOR Entity of which they are:

i) an employee of the EPCOR entity; or
ii) on whose behalf the Employee is providing services of an ongoing nature.

7.3 Non-employees, independent contractors or external third parties (herein "Non-employees") engaged by EPCOR shall have no authority to procure goods and/or services on behalf of EPCOR. Approval of procurements by Non-Employees on behalf of EPCOR is only permitted if previously approved in writing by the SVP of the Business Unit responsible for Procurement.

7.4 Transaction limits in Schedule "A" can be increased based on an identified business need and approval by the Director of the specific Employee.

7.5 Individual Procurement Employee approval limits are based on EPCOR's business needs.

7.6 The Procurement Approval Limits set out in Schedule "A", apply cumulatively per Purchase Order including amendments and change requests for each Approval Group and reflect the appropriate level of oversight required to mitigate risk.

8.0 ROLES AND RESPONSIBILITIES

These roles and responsibilities are designed to facilitate the ongoing administration, maintenance and monitoring of this Policy. The positions designated below are responsible and accountable for ensuring that the specified obligations are met.

8.1 General Counsel

General Counsel is responsible for:

- Ownership of the Policy;
- Approving the Policy and all amendments thereto; and
- Approving any exceptions to the Policy, including the Approval Groups (Schedule "A") as recommended by Senior Managers responsible for Procurement;
- Ensuring that the Policy is accessible to all Employees;
- Ruling on conflicts, matters of interpretation and exceptions in a timely manner as they arise;
- Communication of significant or material Policy changes to BU Senior Vice Presidents, CEO and the Board;
- Establishing and managing processes and controls to effectively administer and enforce the Policy so as to mitigate acts of non-compliance;
- Addressing audit issues and concerns related to the Policy in a timely manner;
- Providing clarification on processes associated with the Policy as they arise;
- Reviewing with the BU Senior Vice Presidents the appropriateness of Policy approval limits, and approving exceptions to the Policy for Approval Groups; and
- Reporting significant acts of non-compliance or other significant matters related to this Policy to the Corporate Controller, BU SVP or the CFO.

8.2 Business Unit (BU) Senior Vice Presidents

The BU Senior Vice Presidents are responsible for:

- Ensuring their respective BUs comply with this Policy;
- Communication of Policy changes to Employees;
- Seeking the advice of the General Counsel on issues related to compliance and interpretation of the Policy; and
- Reporting acts of non-compliance with this Policy to General Counsel, when they arise, in a timely manner.

8.3 Procurement

Each Business Unit's designated Procurement organization includes individuals that participate in procurement activities, each having distinct roles and responsibilities. The following outlines these participants and their responsibilities:

8.3.1 BU Senior Manager responsible for Procurement

The BU Senior Manager responsible for Procurement (Procurement Senior Manager) is responsible for:

- Ensuring the Procurement functional area complies with this Policy;
- Communication of Policy changes to Employees;
- Seeking the advice of General Counsel on issues related to compliance and interpretation of the Policy;
- Reporting acts of non-compliance with this Policy in a timely manner to General Counsel when they arise;
- Recommending exceptions to Procurement Approval Groups to General Counsel;
- Reporting Employee spending limit exceptions during an Emergency to General Counsel;

- Ensuring the procurement of all goods and/or services required by EPCOR are completed in accordance with generally accepted procurement practices and obligations set out by a Regulator;
- Assisting in Employee and Business Unit education regarding this Policy's application; and
- With the assistance of General Counsel, making best efforts to resolve conflicts arising out of the Policy, addressing acts of non-compliance.

8.3.2 Procurement Managers

Procurement Managers are responsible for:

- Administering the Policy on a day to day basis;
- Reviewing and approving procurement documentation within prescribed limits; and
- Ensuring that procurements are completed in accordance with generally accepted procurement practices and obligations set out by a Regulator;
- Encouraging Business Unit use of Supply Arrangements;
- Assisting in Business Unit education regarding this Policy's application;
- Reporting acts of non-compliance or other issues as appropriate to the Procurement Senior Manager, in a timely manner.

8.3.3 Procurement Employees:

Procurement Employees are responsible for:

- Compliance with the Policy;
- Understanding the requirements of this Policy and being familiar with the applicability of other EPCOR policies and procedures in the performance of their duties under this Policy;
- Completing procurements of goods and/or services in accordance with generally accepted procurement practices and obligations set out by a Regulator;
- Creating and approving Purchase Orders within prescribed limits;
- Where practical, utilizing Supply Arrangement for the purchase of goods and/or services;
- Encouraging Business Unit use of Supply Arrangements;
- Assisting in Business Unit education regarding this Policy's application;
- Obtaining guidance from their Manager on all material matters related to the Policy; and
- Reporting acts of non-compliance with the Policy to their Manager in a timely manner.

8.4 Employees

Each Employee is responsible for:

- Compliance with the Policy;
- Understanding the requirements of the Policy and being familiar with the applicability of other EPCOR policies and procedures in the performance of their duties under this Policy;
- Obtaining guidance from the appropriate BU Procurement Senior Manager on all matters related to the Policy; and
- Reporting acts of non-compliance with the Policy to their Manager in a timely manner.

8.5 Risk, Assurance and Advisory Services

Risk, Assurance and Advisory Services is responsible for:

- Conducting periodic audits and reviews with respect to the execution of procurements under this Policy;
- Confirming that actual operating practices are in compliance with this Policy and any applicable procedures;
- Assessing the processes, procedures, limits and controls over the administration, monitoring and application of limit controls; and
- Reporting, as appropriate, acts of non-compliance or other deficiencies observed during the audit process to General Counsel.

9.0 COMPLIANCE

9.1 It is a violation of this Policy to split a purchase into small parcels in order to circumvent the requirements of this Policy or established controls.

9.2 All exceptions, breaches, suggested changes to or conflicts with the authorities set out under this Policy are to be reported to General Counsel as applicable, for further action.

9.3 **NON-COMPLIANCE WITH THE TERMS OF THIS POLICY IS SUBJECT TO DISCIPLINARY ACTION, REMOVAL OF AUTHORITY AND/OR TERMINATION OF EMPLOYMENT.**

10.0 DOCUMENT REVISION HISTORY

Version Number	Date	Author	Change Description
1.0	May 27, 2011	Bryan Hannah	Created new policy
2.0	March 30, 2015	Terri Gentile	Revisions to policy to reflect line of business restructuring, CSOX engagement recommendations; and 3 year maintenance review
3.0	January 1, 2019	Asif Kazani	Revisions to reflect Draw Down Purchase Orders

Generic Identifying Information

Policy Name	EPCOR Procurement Policy
Contact Person	Asif Kazani, Senior Manager, Corporate Procurement and Facilities

Milestone dates

Effective Date	January 01, 2019
Next Review Date	June 30, 2019

Responsibility and Distribution

Executive Sponsor	Jennifer Addison, Senior Vice President, Legal and Corporate Secretary
Senior Manager Reviewers	• Asif Kazani, Senior Manager, Corporate Procurement and Facilities, EUI • Ron Edwards, Senior Manager, Procurement Fleet and Facilities, EPCOR Distribution and Transmission Inc. • Eric Wood, Senior Manager, Supply Chain & Facilities, Drainage Services (EWSI) • Heather Piano, Senior Manager, Supply Chain, EPCOR Water Services Inc. • Brett Wiles, Senior Manager, Engineering & Supply Chain, EPCOR Technologies Inc.
Owner	Asif Kazani, Senior Manager, Corporate Procurement & Facilities
Stakeholders	Business Unit Procurement organizations
Audience	This policy applies to all Employees of EPCOR

SCHEDULE “A” – PROCUREMENT APPROVAL LIMITS

SCHEDULE “A”							
Procurement Approval Limits							
Transaction	**Maximum Purchase Order Value Authorities (M=Millions)**						
	Approval Group 6 **Director**	**Approval Group 5** **Procurement Senior Manager**	**Approval Group 4** **Procurement Manager**	**Approval Group 3** **Contract Analyst**	**Approval Group 2** **Procurement Associate**	**Approval Group 1** **Purchasing Assistant**	**Approval Group 0** **Non Procurement Employee authorizing Blanket Releases**
Purchase Order approval limit authority	Unlimited	up to $1M	up to $500K	up to $250K	up to $125K	up to $75K	up to $10K

EPCOR Utilities Inc. Finance and Accounting Policy and Procedures			
Topic	**Depreciation and Amortization**	Number	FA-007
Category	Property, Plant and Equipment, Intangible Assets	Revision Number	2
Issued by	Accounting Standards Committee	Issued and Effective	Dec 31, 2006
Approved by	Corporate Controller	Revised	Oct 9, 2011

1. Purpose and Scope

1.1 This depreciation policy functions as a guide in the calculation of depreciation and amortization expense for property, plant and equipment (PP&E) and intangible assets for the purpose of producing general purpose financial statements. The intent is to ensure that PPE and intangible assets are properly depreciated in accordance with International Financial Reporting Standards (IFRS).

1.2 This policy refers to depreciation of rate-regulated and non rate-regulated capital assets. All PP&E and intangible assets must be depreciated in a rational and systematic manner over their expected useful economic lives in compliance with IFRS.

2. Definitions and Background

2.1 **Asset –** resource controlled by the entity as a result of past events and from which future economic benefits are expected to flow to the entity.

2.2 **PP&E**– tangible items that:

(a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

(b) are expected to be used during more than one period.

2.3 **Intangible asset -** identifiable non-monetary asset without physical substance.

2.4 **Cost –** the amount of cash or cash equivalent paid or the fair value of other consideration given to construct or acquire an asset.

The cost of an item of property, plant and equipment comprises:

(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;

(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and

(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs, either when the item is acquired or, as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

2.5 **Capital work-in-progress (CWIP)** – an account that includes all costs of capital projects that are incomplete or not yet in service. Capitalized interest, if any, is added in CWIP, as directed in the Capitalization Policy.

2.6 **Depreciation –** the systematic allocation of the depreciable amount of an asset over its useful life.

2.7 **Depreciable amount -** the cost of an asset or other amount substituted for cost, less its residual value.

2.8 **Residual value –** the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.

2.9 **Straight-line Depreciation Method –** A depreciation method that allocates the depreciable amount of an asset over its useful life to reflect a constant annual charge to income.

2.10 **Useful life** – is:

- the period over which an asset is expected to be available for use by an entity; or
- the number of production or similar units expected to be obtained from the asset by an entity.

The useful life is defined in terms of the asset's expected utility to the entity and is governed by physical and economic factors. For example, the end of an asset's physical life will generally be reached when the asset is no longer capable of performing its intended function because of physical wear. The end of the economic life of an asset is generally reached when a replacement asset is more economical to use than the current asset in place.

3. Depreciation Method

3.1 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed. EPCOR currently uses the straight-line method for all capital assets with a finite useful life.

3.2 Under the straight-line depreciation method, the depreciation rate is based on the development and application of a single depreciation rate. Straight-line depreciation results in a constant charge over the useful life if the asset's residual value does not change. This should be used where assets are used to deliver a constant level of service to customers over time.

3.3 The depreciation method used should be reviewed on an annual basis. If a business unit determines that there is a more appropriate method that better reflects the pattern in which the asset's future economic benefits are expected to be consumed, (e.g. the diminishing balance method or the units of production), then the Business Unit Controller should propose such method to Corporate Finance for approval. Any change in depreciation method should be adopted on a prospective basis.

3.4 No depreciation is calculated on assets in CWIP or land.

4. Componentization

4.1. Each part of an item of PP&E with a cost that is significant in relation to the total cost of the item shall be a separate component of the item of PP&E and depreciated separately. Significant components that have the same useful life and depreciation method may be grouped together in determining the depreciation charge.

4.2. The parts of the item of PP&E that are not considered individually significant should be grouped together as a single component and depreciated using a depreciation rate that reflects the approximate consumption pattern of the group of assets.

5. Depreciation Rates & Useful Lives

5.1 All items of PP&E and intangible assets must be depreciated in a rational and systematic manner over their expected useful lives in order to be in compliance with IFRS.

5.2. Under the straightline depreciation method, the depreciation rate to be applied is computed by dividing 1 by the average useful life of the asset account.

5.3. The useful life of an item of PP&E or intangible asset is normally governed by its physical use. However, other factors, such as technical or commercial obsolescence or legal restrictions may also affect the consumption of the asset, and so the estimate of useful life should be the shortest of its physical, technological, commercial and legal life.

5.4. Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management).

5.4.1. The use of the half-year rule is acceptable for assets that are being added which form part of larger asset or system.

5.4.2. However, where the asset addition is a net new asset or an enhancement to an existing asset and this asset is significant, the capital asset groups should use professional judgement to determine whether using the half-year rule will result in a material difference in depreciation recorded for the asset compared to the amount of depreciation that would be recorded if the actual in-service date was used. If the difference would be material, then the half-year rule should not be used and depreciation should begin at the actual in-service date.

5.5. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with IFRS 5 – Non-current Assets Held for Sale and Discontinued Operations and the date the asset is derecognized.

5.6. The useful life and residual value, of an item of property, plant and equipment or intangible asset should be reviewed at each financial year-end or earlier if a significant event occurs prior to the next review. A significant event would include:

- a change in the extent or manner in which the asset is used;
- removal of the asset from service for an extended period of time;
- physical damage;
- significant technological developments; or
- a change in the law, environment, or consumer styles and tastes affecting the period of time over which the asset can be used.

6. Asset Disposals

6.1. A disposal occurs when an item of property, plant and equipment or intangible asset is no longer used by an entity. A disposal can be due to a sale to a third party or the expiration of the useful life of an asset. After an asset disposal occurs the entity no longer has use of the asset.

6.2. Under the straight-line method, when assets are disposed of, the gain or loss is realized in income and the original cost and accumulated depreciation are adjusted to zero. This applies to dispositions at any point in the life of the asset as well as dispositions at the end of the life of the asset.

6.3. Where a replacement part has been capitalized, the item that is being replaced must be derecognized, regardless of whether it has been identified as a separate component.

6.4. Where compensation is received for an asset that has been disposed, the compensation is recognized in income once the compensation becomes receivable. It should not be offset against the cost of any replacement asset.

7. Residual Value

7.1 If a residual value is estimated for an asset subject to the straight-line method, the residual amount is recovered over the life of the asset as a reduction of the depreciation charge.

7.2 The residual value of an asset should be reviewed together with the useful life in accordance with paragraph 5.6 above. Any change to depreciation resulting from a change in the estimated residual value of an asset should be adjusted on a prospective basis.

8. References

IAS 16 – Property, Plant and Equipment

IAS 38 – Intangible Assets

Conceptual Framework for Financial Reporting

9. Related Policies, Procedures and Guidelines

FA-004 - Capitalization Policy

Filed: 2019-01-25
EB-2018-0336
Exhibit 4
Tab 4
Schedule 1
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ENGLP AYLMER GAS SUPPLY PLAN: 2019-2024

DECEMBER 2018

Table of Contents

1. Executive Summary

In the winter of 2013-2014, Ontario experienced much colder than expected weather, which caused the demand and price of natural gas to increase significantly above what was forecasted by the two major natural gas utilities in the province. In response, the Ontario Energy Board (OEB) undertook a review of the adequacy of existing gas supply planning and revised the process to mitigate the cost impact of future extreme weather events on consumers. The output of the review process was a Framework for the Assessment of Distributor Gas Supply Plans (“the Framework”), which guides the OEB’s assessment of the cost consequences of each distributor’s Gas Supply Plan by applying the objectives of transparency, accountability, and performance measurement.

Prior to the winter of 2013-14 Natural Gas Resources Limited (“NRG), the previous owner of the system, was on a Direct Purchase customer of Union Gas under the M9 tariff. NRG did not meet its balancing obligations during February of 2014 incurring significant balancing penalties. As a result, NRG contracted for system gas under the M9 Rate with Union Gas which provided gas supply at OEB approved rates and for load balancing services. NRG also contracted for local production in order to address system integrity and low pressure conditions in the southeast area of the system.

A System Integrity Study completed in 2015 by NRG and SNC Lavalin, recommended the addition of a number of pipelines for system reinforcement, which have subsequently been installed.

Subsequently, ENGLP committed to and engaged Cornerstone Energy Services (“Cornerstone”) to produce a new System Integrity Study (“Study”). This Study further informed ENGLP on the volume and location of gas that is required to be purchased in order to ensure system integrity. The Study is included in this filing. The Study’s objectives include:

1. Identifying system constraints that are likely to lead to unacceptable low pressure conditions under normal operating conditions, including peak day (e.g. low ambient temperature with grain drying)
2. Given forecasted growth, identify system constraints that are likely to lead to unacceptable low pressure conditions through 2024.
3. Identify and evaluate options to address the system constraints, including but not limited to:

   (a) Pipeline additions or modifications
   (b) CNG on-system storage
   (c) Additional supply from Enbridge Gas formerly Union Gas
   (d) Additional supply from others
   (e) NRG Gas Corp. Wells (now ON-Energy Corp)

4. If NRG Gas Corp. (now ON-Energy Corp) are determined to be a prudent option to maintain system integrity, if possible, quantify the volume of gas required to alleviate low pressure areas
5. Develop a capital plan and cost estimate to implement the most cost effective option(s) identified.

The results of this study indicate that local production is necessary and is the most cost effective manner in which to address system integrity and low pressure issues. Cornerstone concluded that indigenous gas supply form existing Lakeview station on Gully Road, although less flexible than CNG, offers the following advantages:

> “1) It will be less expensive to install a small metering and regulating station for this supply point. The gas should also be less expensive when compared to the compression and trucking costs associated with the CNG option.
>
> 2) There is no trucking involved, which avoids the logistical/security of supply issues and negative public perception, but it also means ENGLP is not as limited to the amount of gas they can take. CNG trailers are only so big and logistics become more difficult if ENGLP decides to start pushing more than two trucks a day of CNG into the system from a single decanting station.”

See Exhibit 2, Tab 3, Schedule 2 for a copy of the Study.

ENGLP Natural Gas L.P. Aylmer (“ENGLP”) has developed the following Gas Supply Plan (“Supply Plan”) in accordance with the criteria and guiding principles defined in the Framework. To satisfy the Framework requirements, ENGLP developed a demand forecast that reflects its expected annual load profile over the five year rate period starting January of 2020. The demand forecast was used as an input in determining the appropriate mix between supply from the Enbridge Gas and formerly Union Gas system and local production. To reliably meet forecasted

Peak Day, seasonal, and annual demand, the supply strategy relies on the procurement of gas supply from local production as well as Enbridge and formerly Union Gas.

Applying the Framework's guiding principles of cost-effectiveness and reliability and security of supply, any incremental local gas supply costs will be assessed against the landed costs of natural gas supply alternatives which will ensure this supply will not be greater than the alternative supply source for ENGLP's rate payer. This ensures that cost-effectiveness is balanced against reliability and security of supply, which considers flexibility in commodity procurement. Cost-effectiveness does not supersede reliability in importance, or vice versa, rather the two principles are assessed together, and the final supply option is a balance of the two that ensures customers receive reliable supply at the least cost.

2. Introduction

2.1. Objectives

The objective of the ENGLP's Supply Plan is to develop a right-sized portfolio of natural gas supply assets that ensures consumers receive a cost-effective, reliable and secure natural gas supply. The portfolio is designed to strike a balance between these two guiding principles, which are consistent with the Ontario Energy Board (OEB)'s legislated mandate to protect the interest of consumers with respect to prices and the reliability of gas service. The Supply Plan was developed by following the Framework for the Assessment of Distributor Gas Supply Plans ("the Framework"), which will guide the OEB's assessment of the cost consequences of ENGLP's Supply Plan.

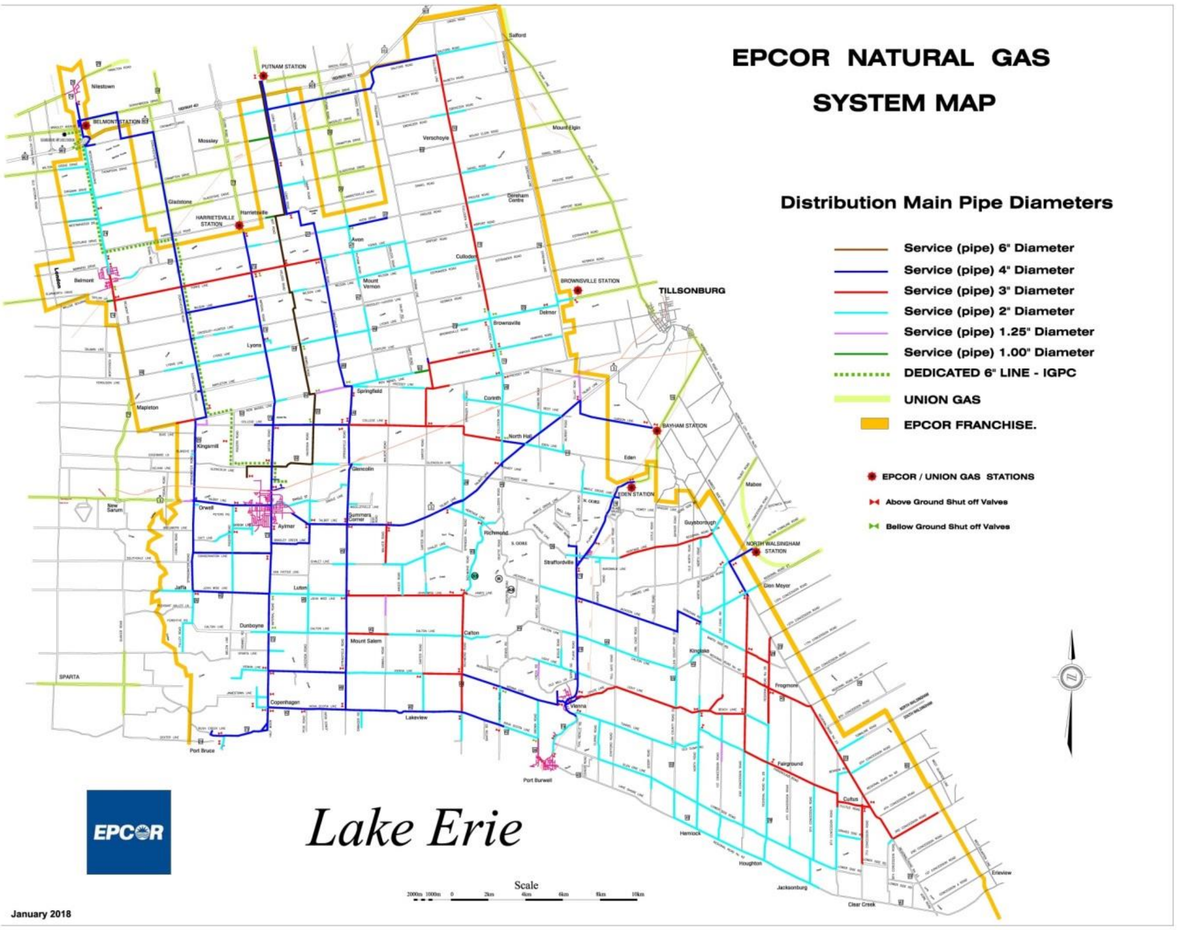
The Framework requires that, along with cost-effectiveness and reliability of supply, the Supply Plan is aligned with public policy objectives. As the current Ontario government has tabled legislation that would repeal the *Climate Change and Low-Carbon Economy Act, 2016*, there are no explicit public policy mandates in place at the provincial level, particularly related to Cap and Trade or Renewable Natural Gas that ENGLP considered while developing the Supply Plan. If public policy objectives are introduced in the future, ENGLP will include an approach to achieving those objectives in the annual updates. For example, ENGLP is closely monitoring the development of the Federal Clean Fuel Standard regulatory framework and will assess compliance options and associated costs when the regulation is enacted.

The Supply Plan is intended to provide strategic direction that will guide ENGLP's ongoing decisions related to its natural gas portfolio such that the Utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods for General Service customers and Contract Customers at least cost. The plan does not commit ENGLP to procuring a set volume and/or source of natural gas, but rather provides a roadmap that is sufficiently flexible, such that reliable and cost-effective natural gas commodity and storage assets can still be procured in the event of changing or unexpected demand, consumption patterns, weather, or market forces.

2.2. Summary of Service Area

The following figure provides a depiction of ENGLP's natural gas distribution service area.

Figure 2.2-1
ENGLP's Natural Gas Distribution Service Area



2.3. Significant Changes

ENGLP expects to continue being a system gas customer of Enbridge Gas and formerly Union Gas under the M9 rate and to augment this supply with local production required to address system integrity issues.

In 2018, NRG CORP divested its wells to On-Energy Corp, an independent third party, and ENGLP will continue to purchase gas under the same terms until the supply contract expires in November of 2020. The OEB in its findings in EB-2010-0018 stated:

> "The Board will allow NRG to recover from ratepayers a maximum annual quantity of 1.0 million cubic meters of natural gas at the rate of $8.486 per mcf. Any additional quantities beyond 1.0 million cubic meters that are purchased from NRG Corp. would only be eligible for

> recovery from ratepayers at current market rates that would be determine quarterly as per the methodology outlined in the Board's Decision of December 6, 2010."

The quantities of gas purchased from NRG above the 1.0 cubic meters was approved at the Union Gas Ontario landed reference price. However, as of the beginning of 2017, Union Gas no longer calculated an Ontario landed reference price. In the absence of this reference price, ENGLP began using Union Gas's Dawn Reference Price for these volumes.

ENGLP expects to continue to require local production throughout the gas supply planning period. The quantities of gas required and price of gas have yet to be determined. Any incremental local production required for system integrity requirements is expected to be capped at a price no greater than the Enbridge Gas and formerly Union Gas System Supply Price so as to minimize any pricing impact to rate payers. In addition, ENGLP expects to re-negotiate pricing under the current contract upon expiration in 2020.

Significant changes from this and future Supply Plans, including resulting consumer impact of those changes, will be included in annual updates and subsequent five-year Supply Plans as warranted.

3. Demand Forecast

To develop a natural gas supply portfolio, ENGLP first constructed a demand forecast.

The utility will service 3 main classes of customers: General Service, Contract and Seasonal customers. These customers fit under six rate classes that include Rate 1 (General Service Rate), Rate 2 (Seasonal Service), Rate 3 (Special Large Volume Contract Rate), Rate 4 (General Service Peaking), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility).

Seasonal (Rate 2) and Contract (Rates 3, 5 and 6) customers make up the majority of EPCOR's demand profile by volume (64.0%). Currently, there are 11 contract customers that make up majority of EPCOR's demand profile by volume (62.0). The majority of the contract demands consumption is attributed to the Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility (58.4%) and growing due to a recently completed expansion. There are 53 seasonal customers that make up 2.0% of EPCOR's demand profile and consist mainly of tobacco farming and curing customers (non-interruptible) that use gas mainly during the months of August and September.

General Service customers (residential, commercial, and industrial) make up the remaining 36% of EPCOR's demand profile, and fall under Rate Classes 1 and 4. Residential customers make up majority of the General Service demand profile (approximately 67.8%) and currently there are 8,363 customers that fall under this classification.

Commercial customers make up approximately 20.4% of the General Service demand profile and currently there are 477 customers under this classification. Both customer segments have flat, non-weather dependent demand requirements during the summer period (April to October), and heat-sensitive demand during the winter period (November to March). Industrial customers have a non-interruptible (Rate 1) and an interruptible (Rate 4) component and make up approximately 11.8% of the General Service demand profile. Currently, there are 67 non-interruptible (Rate 1) and 36 interruptible (Rate 4) industrial customers in the EPCOR natural gas system.

System forecasted growth includes:

- Customers that haven't been serviced in the past (i.e. grain dryers, distributed generation)
- New mains in densely populated areas of new municipalities, including customers that Enbridge Gas and formerly Union Gas cannot serve
- 1% per year everywhere else.

The following Tables provide ENGLP's Customer Connections Forecast and Annual Customer Service Demand Forecast by Rate Class. To determine the forecasts below, the forecasted 2020 values provided by Elenchus in their Weather Normalization and Distributions System Load Forecast (Exhibit 3, Tab 2, Schedule 1) have been inflated annually by the factors determined by Elenchus.

Table 3-1
Forecast of Customer Connections

Connections		2018	2019	2020	2021	2022	2023	2024
R1	Res	8,363	8,616	8,877	9,138	9,398	9,659	9,919
R1	Comm	477	485	494	503	511	520	529
R1	Ind	67	67	68	69	69	70	70
R2		53	52	50	48	47	45	43
R3		6	6	6	6	6	6	6
R4		36	37	38	39	40	41	42
R5		4	4	4	4	4	4	4
R6		1	1	1	1	1	1	1
Total		9,007	9,269	9,538	9,807	10,077	10,346	10,615

Table 3-2
Forecast Annual Customer Service Demand, by Rate Class

M3's		2018	2019	2020	2021	2022	2023	2024
R1	Res	16,836,357	16,555,631	17,043,677	17,544,153	18,044,466	18,544,779	19,045,091
R1	Comm	5,060,879	4,769,270	4,851,704	4,937,294	5,023,014	5,108,734	5,194,454
R1	Ind	1,873,654	1,731,722	1,743,215	1,756,367	1,769,486	1,782,605	1,795,723
R2		1,381,945	1,322,665	1,280,413	1,238,148	1,195,896	1,153,644	1,111,392
R3		1,893,687	1,801,305	1,721,684	1,721,682	1,721,682	1,721,682	1,721,682
R4		1,056,298	1,116,228	1,149,006	1,181,784	1,214,562	1,247,340	1,280,118
R5		673,249	685,748	685,748	702,541	719,334	736,128	752,921
R6		40,374,973	59,243,876	59,243,876	59,243,876	59,243,876	59,243,876	59,243,876
Total		69,151,042	87,226,445	87,719,322	88,325,844	88,932,315	89,538,786	90,145,257

Source: Elenchus Analysis,

4. Supply Options

4.1. Key Assumptions

Balancing system gas supply and local gas production are considered for the procurement of natural gas commodity in order to meet the demand forecast established in Section 3, and while the demand forecast serves as the primary input used to develop the Supply Options, the following base assumptions also underpin each option:

4.1.1. Weather

ENGLP retained Elenchus to provide a Weather Normalized Distribution System Load Forecast. See Exhibit 2, Tab 3, Schedule 2 for a copy of this report.

4.1.2. Commodity

ENGLP receives it’s commodity under the bundled M9 rate which is based on Enbridge Gas formerly Union Gas’ OEB approved WACOG Application.

4.1.3. Transportation

ENGLP incurs gas transportation costs (to Enbridge Gas and formerly Union Gas) for storage, load balancing, and transportation across Enbridge Gas and formerly Union Gas' system to ENGLP's distribution system. These costs are recovered in ENGLP's delivery charges as reflected in the Application.

ENGLP currently contracts for an annual Contract Demand with Enbridge Gas and formerly Union Gas. ENGLP will evaluate its Contract Demand requirements with Enbridge Gas formerly Union Gas on an annual basis and, will look to maximize its usage and minimize over run charges under this contract. ENGLP analysis will include contracting for firm local production, where and when available, in an effort to minimize these transportation costs on behalf of ENGLPs rate-payers.

4.1.4. Storage

ENGLP relies on its contract with Enbridge Gas and formerly Union Gas for storage, load balancing and transportation. ENGLP will need to balance its annual contract demand requirements with Enbridge Gas and formerly Union Gas –which requirements include embedded storage and load balancing with any incremental local production it procures.

4.1.5. Daily Balancing Management

ENGLP is not required to Daily Balance its gas supply as that service is provided by Enbridge Gas and formerly Union Gas under the M9 service agreement.

4.2. Description of Supply Options

Cornerstone identified alternative supply options for ENGLP which included the following:

(a) Pipeline additions or modifications
(b) CNG on-system storage
(c) Additional supply from Enbridge Gas and formerly Union Gas
(d) Additional supply from others

Ultimately these options were determined to be less attractive than an indigenous source of gas being available. In addition to cost consideration, public convenience was also a consideration.

As an example the introduction of CNG would mean up to four CNG trucks a day operating on local roads during the winter season when trucking logistics can be challenging.

4.3. Additional Considerations

In view of the Utility's previous experience following the winter of 2014 and the subsequent financial penalties no other rate classes were considered at this time.

4.3.1. Long-Term Contracts

ENGLP intends to negotiate a long term supply agreement to ensure there is sufficient local production to take advantage of capital invested in any expansion or re-enforcement pipeline designed to supply local production. A long term supply contract will ensure capital improvement projects identified in the Capital Plan undertaken to address system pressure issues are optimized.

In determining the parameters for a long-term gas supply contract ENGLP will undertake an assessment of the landed costs of the natural gas supply as compared to possible alternatives. Furthermore, ENGLP will conduct a risk assessment including forecasting risk, operational risk; commercial and regulatory risk associated with any long-term gas supply agreement and prepare to address these risks in order to minimize the impacts to its ratepayers.

Gas Supply Plan Recommendation

Given ENGLP's limited size and resources the Utility recommends it continue its strategy of contracting with Enbridge Gas and formerly Union Gas for the M9 rate including system supply. In addition, to continue to purchase local production in order to augment Enbridge Gas and formerly Union Gas' system supply to ensure reliability of the ENGLP system.

Accordingly, ENGLP is requesting that the Board allow it to purchase 1.0 million m3 of natural gas from On-Energy at a price of $8.486 per MCf until the contract expires in 2020. ENGLP has identified the Belmont and Lakeview reinforcement projects to be undertaken in 2019 in order to ensure that current customers in these areas continue to receive reliable service. These projects will effectively provide access to incremental natural gas which will address declining production from the existing gas wells and load growth. As stated in section 4.3.1 ENGLP intends to negotiate a long term gas supply agreement to provide the incremental natural gas required.

5. Gas Supply Plan Execution & Risk Mitigation

5.1. Procurement Processes and Policies

Leading into each contract year (July for IGPC and November for Direct Purchase and System Gas customers) ENGLP will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge Gas and formerly Union Gas under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). ENGLP 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 and formerly Union Gas.

ENGLP's has an ongoing review process with its System Gas and Direct Purchase Customers under Rates 3 and 5 is to ensure provisions are in place for these customers to not exceed the established Firm Contract Demand. This will ensure the customers consume within the established Firm Contract Demand in the same manner that ENGLP has to operate within the limits set by Enbridge Gas and formerly Union Gas.

ENGLP will also conduct a review of its entire Rates 3, 5 and 6 customers to ensure they are meeting the Minimum Annual Volume Requirements during each contract year as specified in the rate class descriptions. Further, when a full year of consumption history is available per customer, ENGLP will determine the appropriate rate class for each (i.e. determine if they fit under Rate 2 or Rate 4 rather than Rate 1 or if they are big enough to fit a contract rate (Rate 3 or Rate 5)). This review will also be conducted if there is a significant change in consumption (volume and/or profile) of an existing customer.

5.2. Evaluation of Procurement Process and Policies

The procurement processes and policies are evaluated on the following criteria:

- ***Reliability of supply:*** Procurement processes for commodity are evaluated on whether they allow the adjustment of procurement volumes to match expected demand, and whether processes and policies may hinder ENGLP's ability to procure supply in a timely manner. Procurement process and policy also allow for the procurement of additional gas in times when demand exceeds supply.

- ***Rate Predictability:*** Policies will adhere to the Supply Plan as closely as possible to ensure commodity and storage assets are procured based on a framework that has been established to result in natural gas supply at least-cost to consumers.

- ***Flexibility:*** Policies are flexible to ensure changes in procurement volumes and changes in strategy be adapted in a timely manner when required, and that procurement processes and policy do not significantly hinder the flexibility of other aspects of the plan.

- ***Continuous Improvement*****:** ENGLP will review and improve on procurement processes and policies on an annual basis.

5.3. Risk Mitigation Strategy

A key aspect of the Supply Plan execution is the existence of risk mitigation strategies.

5.3.1. Description

Risks identified are:

1. M9 Rate no longer being offered by Enbridge Gas and formerly Union Gas
2. Accelerated depletion of local gas production wells (currently under contract)

5.3.2. Evaluation

M9 Rate no longer being offered

ENGLP is aware that Enbridge Gas and formerly Union Gas has filed an M17 rate designed to provide transmission service to embedded distribution utilities. ENGLP's view is that this rate is unfavourable as compared to the M9 rate and does not intend to subscribe to this service. ENGLP further understands that Enbridge Gas and formerly Union Gas will continue to offer the M9 rate to the ENGLP.

Accelerated depletion of local gas production wells (currently under contract)

ENGLP retained GSA Energy to identify the remaining production life of NRG Corp's wells as part of its acquisition of NRG. GSA Energy's review identified the significant economic depletion in the remaining production life of NRG Corp's Wells.

Although these wells have continued to produce gas at a steady state, ENGLP has identified the Belmont and Lakeview reinforcement projects to be undertaken in 2019 in order to ensure that current customers in these areas continue to receive reliable service. These projects will effectively provide access to incremental natural gas which will address declining production from the existing gas wells and load growth

6. Current and Future Market Trends Analysis[1]

As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform ENGLP of any changes in natural gas market fundamentals which may have the potential to impact the Utility's ability to execute the Supply Plan.

Natural gas supply to the Ontario market is expected to remain strong over the next few years. Natural gas primarily flows into the Dawn Hub ("Dawn") from the Western Canada Sedimentary Basin (WCSB) and the Marcellus and Utica shale plays in the Appalachian region of the United States (U.S.).

Historically, the WCSB has been the major gas supplier to markets in Eastern Canada, but the emergence and rapid development of Appalachian shale supply has significantly increased U.S. supply into Eastern Canada, displacing WCSB gas, and the trend is expected to continue. The rise in production in the Appalachian region has significantly changed the supply of natural gas to Ontario and the flow of natural gas on the TransCanada Pipe Line (TCPL) system to Eastern Canada. Until 2012, the WCSB accounted for nearly 100% of the supply to the Eastern Canada markets through the TCPL and Alliance/Vector pipelines and has been a large gas exporter to the U.S. Northeast. The current share of WCSB supply in Eastern Canada varies between the winter and summer and is approximately 65% and 75%, respectively as reflected in Figure 7-1, below.

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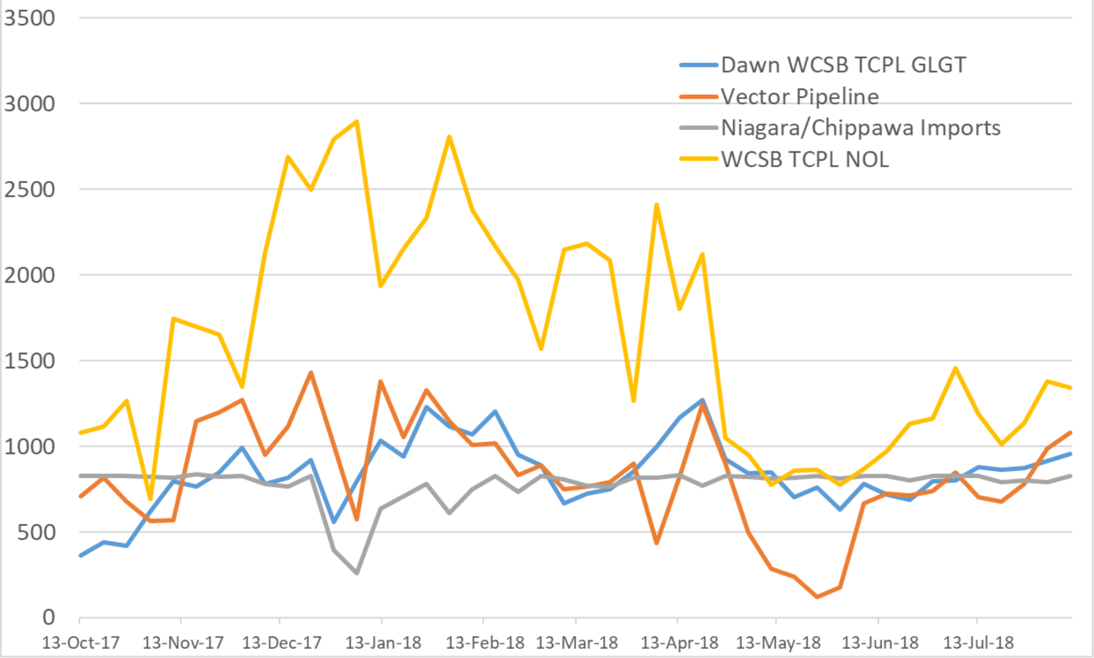
[1] Section 6-" Current and Future Markets Trends Analysis" is an excerpt from a 2018 Report commissioned by and provided to EPCOR by Blackstone Energy.

Figure 7-1
Major Supply Sources of Ontario Natural Gas (MMcf/day)[2]



Production in the Marcellus and Utica basins is expected to reach 23 Billion Cubic Feet (Bcf) per day by the end of 2018, up 18 Bcf per day over a 10-year period production. The Appalachian region has been the key driver of the 37% increase in U.S. dry natural gas production over the last 10 years, in contrast to WCSB production which has decline by 5 % over the same period (**Figure XX**). Currently, the growth of natural gas production in the Marcellus and Utica basins is constrained by the lack of available takeaway pipeline capacity to move it to new markets.

WCSB supply is expected to decline going forward, with the large decrease in drilling activities due to the sustained low natural prices gas prices. However, supply from WCSB into Eastern Canada is not expected to decline further as WCSB producers are increasingly looking at market outside the province of Alberta. The competitiveness of the Appalachian supply has led to large de-contracting of transportation on the TCPL of supply from the WCSB to the Eastern markets and to the U.S. Northeast. The current supply excess in the WCSB has pushed down prices significantly over the last three years and has motivated Alberta producers to contract for large volumes of transportation capacity on the TCPL mainline to Dawn. For example, contracts for 10-Year Long Term Fixed Price for 1.3 Bcf/day of transport will come into effective

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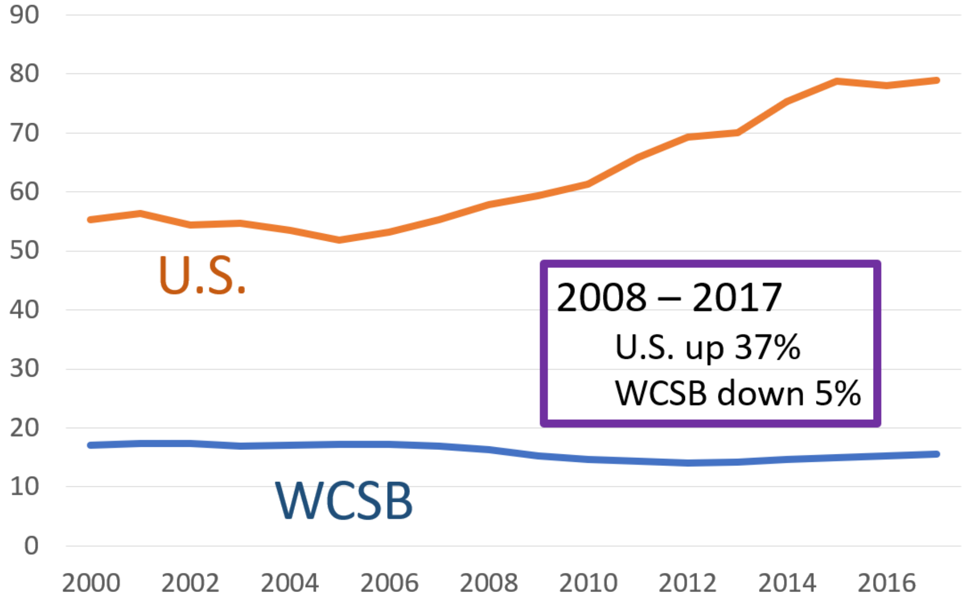
[2] Source: EIA, Energy Institute of America.

November 1, 2018 and more recently, Alberta producers have signed for an incremental 0.9 Bcf/day of capacity at Empress effective November 2021.

Figure 7-2
Marketable Natural Gas Production (Bcf/day)[3]



Driven by its robust supply economics and proximity to the U.S. Northeast and Eastern Canadian markets, Appalachian supply now fulfills most of the gas demand in the U.S. Northeast, has replaced most of the WCSB supply in that region, and in the last few years has made large inroads in Eastern Canada. The latter refers to the reversal of the Niagara/Chippewa exports points in 2012 and 2015, respectively. Last year's expansion of the Vector pipeline (0.45 Bcf/day of incremental summer capacity) at Dawn has further increased supply into Eastern Canada and added additional downward pressure on the Dawn basis. Proposed and under-construction pipeline projects such as Rover and Nexus (**Figure XX**), will continue to increase competitive pressures on WCSB volumes serving eastern markets via the Mainline.

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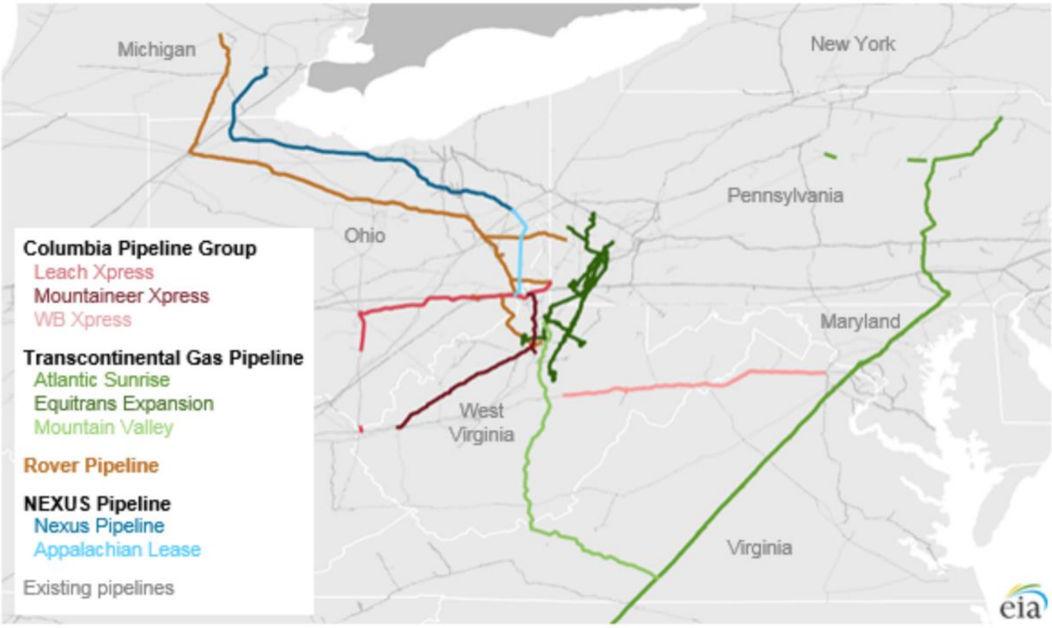
[3] Source: Energy Institute of America, Canadian Association of Petroleum Producers.

Figure 7-3
Existing and Planned Pipelines in the U.S. Northeast[4]



Phase 2 of the Rover pipeline came online in mid-2018, flowing 3.25 Bcf/day of new capacity into Midwestern markets, including the Dawn hub. The NEXUS Pipeline is expected to come online in Q3 2019 and add 1.5 Bcf/day. The caveat to these pipeline developments is that Vector pipeline capacity is not increasing. The last expansion on Vector in 2017, pushed winter and summer capacity to 1.75 Bcf per day. Rover and Nexus will add incremental supply from the U.S. that will compete with existing volumes on Vector and have the potential to add further downward pressure on the Dawn-NYMEX basis. The incremental supply will also increase competitive pressures on the WCSB volumes serving eastern markets via the Mainline.

The potential for the reversal of the Iroquois pipeline exists due to competition with Marcellus volumes in U.S. northeast markets but this reversal is likely several years away. Firm contracted volumes into Iroquois from Canada have decline to 0.5 Bcf/day, the physical capability into Iroquois is 1.2 Bcf/day. TCPL recently issued an open season that offers a steep discount on the approved toll from Empress to North Bay and potential shippers will have the opportunity to take their gas to downstream markets in Eastern Canada, such as Iroquois. If successful, the open season would likely push out further the potential for a reversal of Iroquois. Marcellus is the

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[4] Source: EIA, Energy Institute America.

largest producing field in the world, the Iroquois pipeline is depreciated, and the tolls would be quite competitive to move supply into Canada. As approvals of pipeline expansions in the U.S. often face resistance and delays, meaning the possible reversal is several years away. In the future, TCPL could offer a more competitive open season that will reduce the likelihood of Iroquois reversal. On the U.S. side, FERC has also recently announced that the Northern Access Pipeline on National Fuel may proceed and could add near 300 Mmcf/day of new import capacity at Chippewa.

Given the above market outlook and future trends analysis, there are no major changes expected in the North American natural gas market over the next three years that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan and its ability to deliver on the guiding principles of cost-effectiveness, reliability and security of supply.

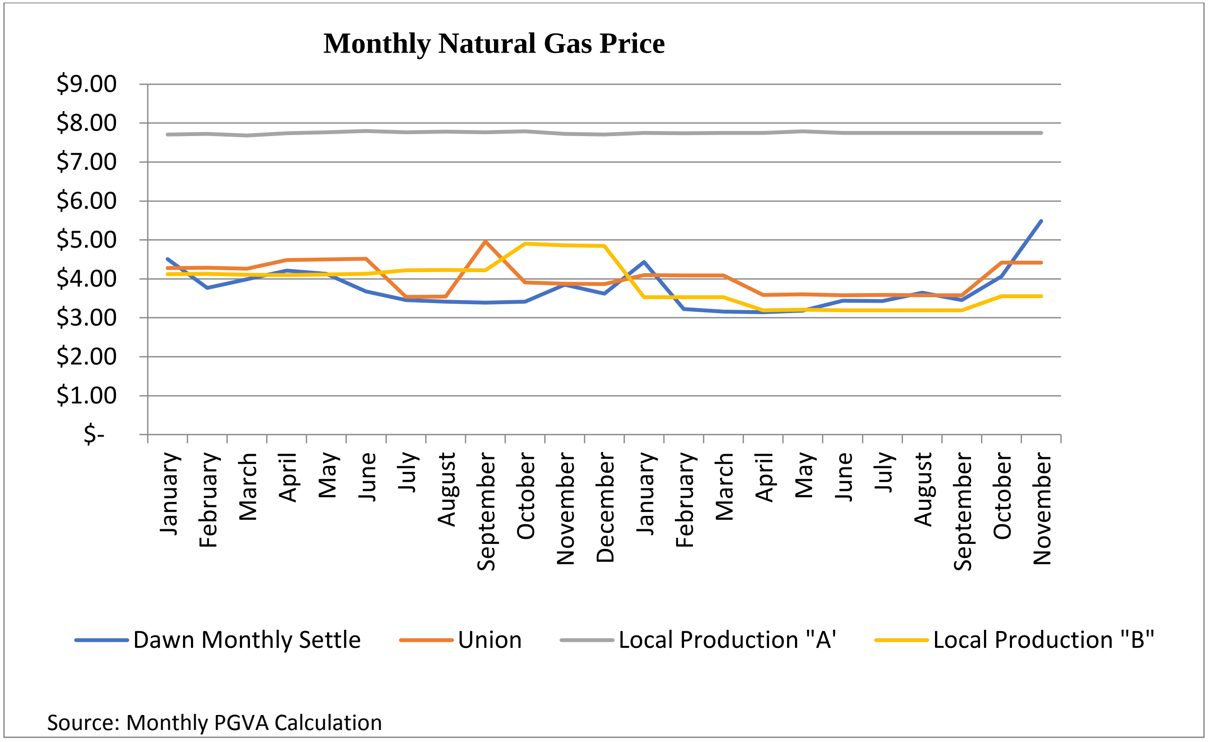
7. Performance Metrics

The Supply Plan will be assessed on four key performance metrics, Reference Price, Cost of Servicing the Portfolio, Rate Predictability and Flexibility. Once the Supply Plan is executed, ENGLP’s portfolio will be reviewed and will be compared to these performance metrics to determine how it has met the criteria set out in the Framework.

7.1. Reference Price

The average cost of gas purchased at Dawn for the horizon of the Supply Plan, will be used as a performance metric to compare how ENGLP’s local production pricing performs compared to alternatives-notably system gas from Enbridge Gas and formerly Union. For reference Figure 8.1-1 shows the historical Monthly Dawn Settlement Price, the cost of gas the Utility purchases from Enbridge Gas and formerly Union and the cost of gas the Utility purchases from of local production. The cost of incremental local production will be measured against these indices.

Figure 8.1-1
ENGLP's Monthly Natural Gas Price



Source: Monthly PGVA Calculation

7.2. Cost of Servicing the Portfolio

The cost of servicing the Portfolio is largely embedded in the Enbridge Gas and formerly Union Gas rate. There are nominal incremental charges associated with general administration of the local gas production contracts. The General Administration charges are outlined in the Application.

7.3. Rate Predictability

ENGLP's rate is largely weighted to Enbridge and formerly Union Gas's OEB approved WACOG which is reviewed and approved quarterly by the OEB.

7.4. Flexibility

ENGLP is embedded within the Enbridge Gas and formerly Union Franchise limiting its transportation options to the upstream inlet to the Enbridge Gas and formerly Union Gas's distribution network. ENGLP is however in discussions with independent local producers to provide flexibility of supply in order to address system integrity issues. Furthermore ENGLP offers interruptible rates to its customers (Rate 5) in order to provide peak day service.

7.5. Diversity of Supply

While the OEB Framework requires ENGLP to provide a description of diversity in supply and transportation assets, Diversity of Supply is not included as a performance metric for ENGLP as ENGLP plans to procure gas only from Enbridge Gas formerly Union Gas and from local producers, as described above.

8. Continuous Improvement Strategies

Continuous improvement to the supply planning process that is undertaken by ENGLP is an important element of the transparency objective of the OEB framework. ENGLP continues to proactively evaluate new supply and transportation options. Unchanged, however, is ENGLP's application of the gas supply planning principles and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs.

ENGLP will also continue to proactively identify new opportunities to meet its gas supply obligations while meeting the OEB Framework Assessment criteria. ENGLP will also continue to review and improve the information it reviews for market outlook and forecasting purposes. ENGLP has filed a leave to construct to build the gas distribution system for the South Bruce area. There may be opportunities to combine gas supply plans for both these areas but ENGLP believes this opportunity is beyond the scope of this gas supply plan.

9. Appendices

9.1. Appendix A: Average Annual Usage

Breakdown of Average Annual Usage, By Customer Segment (m^3)

Avg M3/Cx		2018	2019	2020	2021	2022	2023
R1	Res	2,013	1,921	1,920	1,920	1,920	1,920
R1	Comm	10,615	9,828	9,821	9,821	9,821	9,821
R1	Ind	28,140	25,660	25,636	25,636	25,636	25,636
R2		25,930	25,608	25,608	25,608	25,608	25,608
R3		315,615	300,218	286,947	286,947	286,947	286,947
R4		29,342	30,237	30,237	30,237	30,237	30,237
R5		168,312	171,437	171,437	171,437	171,437	171,437
R6		34,154,944	35,297,545	35,297,545	35,297,545	35,297,545	35,297,545

9.2. Appendix B: Key Terms

Balancing Gas:	The volume of gas purchased for the purpose of clearing the Cumulative or Daily Operating Imbalance.
Baseload Gas:	The minimum amount of natural gas delivered or contracted over a given period of time at a steady rate or price structure.
Cap and Trade:	Ontario's cap and trade program is a market-based system that sets a hard cap on greenhouse gas emission. The cap is lowered over time and participants in the program must procure compliance instruments (e.g. emissions allowances, offset credits) to cover their annual emissions.
Clean Fuel Standard:	a performance-based approach to reducing the carbon intensity of fossil fuels that would incent the use of a broad range of low carbon fuels, energy sources and technologies, such as electricity, hydrogen, and renewable fuels, including renewable natural gas. It would establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels, and would go beyond transportation fuels to include those used in industry and buildings.
Contract Customers:	The maximum volume or quantity of gas that ENGLP is obligated to deliver in any one day to a customer under all services or, if the context so requires, a particular service at the consumption point.
Contract Demand ("CD"):	Means the maximum volume or quantity of Gas that Enbridge Gas formerly Union is obligated to deliver in any one Day to ENGLP under all Services or, if the context so requires, a particular Service at the Consumption Point
Contract Year:	Means a period of twelve consecutive Months beginning on the Day of First Delivery and each anniversary date thereafter unless mutually agreed otherwise.
Dawn:	Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Enbridge Gas formerly Union Gas' supply, storage and transmission systems meet. A number of other pipeline systems (e.g., TCPL, Vector) are interconnected to Union Gas' distribution system at Dawn.

Gas Day:	A period of 24 consecutive hours, beginning at 10:00 am ET. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period commences.
Gas Year:	A period of twelve (12) consecutive months usually beginning on November 1st and continuing until October 31st of the following year.
General Service Customer:	Insert Definition of rate class customers
Heating Degree Day:	The number of degrees that a day's average temperature is below 18°C, which is the temperature below which buildings need to be heated.
Peak Day:	The 24-hour period of greatest total gas send out. For the purpose of this Supply Plan, ENGLP assumes a Peak Day is when demand on a given day is 50% higher than the average forecasted demand in that month.
Rate 1 – General Service Rate:	Includes residential, commercial and industrial customers that constitute majority of the customer base in the ENGLP natural gas system
Rate 2 – Seasonal Service:	Includes mainly tobacco farming and curing customers (non-interruptible) that consume gas during the months of August and September. These customers are charged a different Delivery Charge for gas consumed between the months of April 1 through October 31 and November 1 through March 31.
Rate 3 – Special Large Volume Contract Rate:	Includes customers who enter into a contract for the purchase or transportation of gas: • for a minimum term of one year; • that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; • a qualifying annual volume of at least 113,000 m^3.
Rate 4 – General	Include primarily industrial customers whose operations can readily

Service Peaking:	accept interruption and restoration of gas service within 24 hours' notice. These customers are charged a different Delivery Charge for gas consumed between the month of April 1 through December 31 and January 1 through March 31.
Rate 5 – Interruptible Peaking Contract Rate:	Includes customers who enter into a contract for the purchase or transportation of gas: • for a minimum term of one year; • that specifies a daily contracted demand for interruptible service of at least 700 m3 • a qualifying annual volume of at least 50,000 m3.
Rate 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility:	Rate specific to the IGPC ethanol production facility located in the Town of Aylmer.
	The Western Canadian Sedimentary Basin (WCSB) is a vast sedimentary basin underlying 1,400,000 square kilometres (540,000 sq mi) of Western Canada including south-western Manitoba, southern Saskatchewan, Alberta, north-eastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins.
Winter Period:	The period from November 1 to March 31, representing a total of 151 days (152 days in a leap year)

BACKGROUND

EPCOR Utilities Inc. ("EPCOR") asked Willis Towers Watson to review the approach and results of EPCOR's compensation review for its recently acquired gas distribution business in Aylmer, Ontario in support of Applications to be filed with the Ontario Energy Board in the first quarter of 2019.

Our Memorandum covers our review of the methodology used by EPCOR and examines, at a high level, the compensation changes made as a result of their review. For this review, we relied on information provided by EPCOR (e.g., their calculations, copies of collective agreements, job descriptions). We have not conducted a separate review of compensation and benefits as part of this engagement.

REVIEW OF METHODOLOGY

The standard approach that we would use in these types of engagements would be to conduct a compensation and benefits review using market data relative to EPCOR's approved peer group, typically sourced from Willis Towers Watson's proprietary compensation and benefit surveys and containing market data for both represented and nonrepresented employees in consideration of the broader market for talent. Information from collective agreements would be used only as a secondary reference to validate the findings from the surveys.

In this case, the Aylmer business unit is a relatively recent acquisition and small (18 employees in total). There are few industry peers located in Ontario that participate in compensation and benefit surveys; therefore, EPCOR has yet to adopt a peer group for Ontario-based employees. EPCOR's currently approved peer groups were developed for EPCOR's western Canadian employee base and are regionally biased to include more western Canadian v. Ontario-based employers. Over time, EPCOR's Ontario business is expected to expand which will facilitate the development of an approved peer group specific to the Ontario labour market and compensation and benefit benchmarking based on the standard approach.

In the meantime, EPCOR has taken a transitional approach relying on data from collective bargaining agreements, which Willis Towers Watson believes is reasonable given the circumstances; however, we note that compensation levels for represented employees at these levels tends to be higher than nonrepresented employees in the utility sector and broader general industry and the comparisions to the collective bargaining agreements assumes that the labour market for talent (i.e., the companies from which EPCOR could recruit or to whom they could lose employees) would be only against other represented workforces.

EPCOR reviewed six collective agreements covering Ontario-based utilities for employers such as Enbridge, Union Gas and municipallly owned utitilities in Kingston and Kitchener. Geographically, the agreements cover employees in Southern, Southwestern and Eastern Ontario. The selection of agreements addresses compensation in a mix of small and large labour markets and considers private and public sector utilities, generally aligned with our understanding of the labour market for talent.

For purposes of compensation decision-making and salary administration, the Aylmer employees have been grouped into the following classifcations:

- Management
- Field
    - Senior Field Tecnician
    - Field Technician
    - Construction Lead
    - Field Technician Support/Helper
- Administration
    - Admin 3
    - Admin 2
    - Admin 1

We understand that EPCOR benchmarked the Aylmer positions against the jobs in the collective bargaining agreements based on their understanding of the underlying roles and responsibilities. While the job titles of the matches used generally appear appropriate, we have not validated the specific matches selected as benchmarks.

Average bottom and top steps were calculated from the wage rate minimums and maximums for the applicable matches in the collective agreements. From this data, an EPCOR top step (i.e., fully qualified, fully certified employee) was developed for each of the Field and Administration classifications The Field wage grid features three steps and the Administration grid has four steps.

EPCOR's compensation philosophy, consistent with standard methodologies for compensation benchmarking, targets the market 50th percentile. The 50th percentile is the middle data point in an ordered data set and helps to minimize the impact of outliers. Given the limited number of data points in EPCOR's analysis (e.g., two or three), the 50th percentile is more statistically challenging to calculate and EPCOR's use of an average is reasonable to use in this case.

Individual pay adjustments were made based on individual compensation positioning relative to the market competitive wage grids.

OBSERVATIONS ON COMPENSATION CHANGES

The benchmarking by EPCOR identified some significant differences relative to the market data as summarized in the table below.

	Current Hourly Rate	% Difference Versus Market Bottom Step	% Difference Versus Market Top Step
Sr. Field Tech with GPI	$33.50	0.1%	-5.1%
Field Tech with GPI	$31.00	12.5%	-0.9%
Field Tech	$27.00	-2.0%	-13.7%
Construction Lead	$24.50	-9.7%	-20.1%
Field Tech Support/Helper	$19.00	-31.2%	-34.7%
Admin 3	$27.30	-3.2%	-14.7%
Admin 2	$21.25	-24.1%	-31.1%
Admin 1	$19.04	-28.3%	-34.4%

EPCOR is intending to fully adjust employee rates to market competitive levels by 2020 in support of attraction / retention of key talent needed to successfully deliver on the operational priorities. While the increases would be substantial, we note the adjusted wages and salaries would be in line with the average wage rates for the benchmark positions within the collective agreements that were reviewed as part of this analysis.

Further as a secondary check, EPCOR has indicated the Administration and Field roles would be considered frontline roles in EPCOR's job structure. The average 2019 salary (after market adjustments) for the Administration and Field roles will be approximately $60,000. In comparison, market data accessed from a 2017 Willis Towers Watson study (reflecting 2016 compensation practices) using EPCOR's approved peer group indicated frontline roles had a 50th percentile salary 10% higher and target total cash 20% higher than the average salary for Administration and Field roles in Aylmer, which suggests the new wages and salaries are generally reasonable.

In addition, a target short-term incentive, a group retirement savings plan (RSP) and group benefits have been provided in line with broader EPCOR practice. EPCOR has indicated that among the collective agreements examined, Union Gas provides a short-term incentive to its covered employees and that there are other utilities providing short-term incentives at this level. A review of the proposed target total cash (adjusted wage/salary and target short-term incentives) for the EPCOR positions indicates the EPCOR values are reasonably aligned with the collective agreement data, even if the peers only receive wage/salary. EPCOR indicated that they believed that the group RSP and group benefits were in line with those offered by Ontario utilities which participate in the OMERS pension plan.

CONCLUSION

In light of the newness and relatively small size of the Aylmer business unit, the EPCOR benchmarking approach using collective bargaining agreements as the main reference point is reasonable as a transition approach. The pay changes resulting from their benchmarking are significant but seem to be reasonable compared to the comparators in the collective agreements and also with reference to our previous benchmarking for EPCOR relative to its approved western Canadian focused peer group.

Robert Fairholm Economic Consulting

A Corporate Partner of the Centre for Spatial Economics

Final

Forecast Values of Escalators for 2018 to 2020

Prepared for:

EPCOR Energy Alberta GP Inc.

Prepared by:

Robert Fairholm Economic Consulting Inc.

A Corporate Partner of the C_4SE

March 3, 2017

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Executive Summary

This report provides historical and forecast values of various recommended escalators for 2018 to 2020 for use by EPCOR Energy Alberta GP Inc. ("EEA")—which is called EPCOR for this report. The recommendations are summarized in the following table:

Table ES 1: Recommended Escalators

Category	**2018F**	**2019F**	**2020F**
1 Contractor Costs	2.3	2.3	2.7
2 Other Costs	2.1	2.3	2.1

Notes: Values for 2018-2020 are forecasts (F).

1. Introduction

This report has been prepared for EPCOR by Robert Fairholm Economic Consulting Inc. a corporate Partner of the Centre for Spatial Economics (C_4SE). The report provides cost forecasts over the period from 2018 through 2020.

Sections 2 - 4 describe the proposed escalators and provide annual forecast values for the years 2018 – 2020. Since historical values for all concepts are not available through 2016, estimated values for the missing data are also included. In the tables that present the data, the actual data are shown in the last row of the table instead of the forecast averages in those cases where the average forecast value differs from the data subsequently released by Statistics Canada. As described in these sections, forecast values are obtained from information released by independent organizations that provide forecasts, including Financial Institutions, Alberta Treasury and Finance, The Conference Board of Canada (CBOC) and the Organization for Economic Co-operation and Development (OECD). Forecasts were released between November 2016 and February 2017.

Section 2 contains forecasts of growth in wages and salaries per employee in Alberta that are appropriate for use by EPCOR in escalating contractor costs. These can also be used as a placeholder for union escalator rates until collective agreement negotiations are complete and a settlement is reached.

Section 3 contains forecasts of the All-Items Consumer Price Index (CPI) for Alberta. The calculated inflation rate can be used directly as an escalator for costs other than materials costs and contractor costs. The value for Alberta CPI for 2016 has been released by Statistics Canada and has been used in Table 3.

2. Contractor Costs

Most contractors primarily supply labour services, therefore it is recommended that the escalator for contractor costs use the forecasted growth in wages and salaries per employee in Alberta for 2018-2020. A few forecasts of various wage measures for Alberta are available. However, only the Conference Board of Canada (CBOC) produces an independent forecast of the wage rate (wages and salaries per employee) that is available publically for purchase as a separate data series. The CBOC does not produce forecasts of wage rates for individual industries. So the aggregate wage rate for the province was used instead. The most recent forecast from the CBOC was released December 2016. The aggregate wage inflation rates are shown below in Table 1.

TABLE 1: Actual and Forecast Values of Alberta Aggregate Wage Rate

(Annual Percent Change)

	2014A	**2015A**	**2016P**	**2017F**	**2018F**	**2019F**	**2020F**
CBOC	4.6	-1.8	-2.9	1.5	2.3	2.3	2.7

Notes: Values for 2014-2015 are actual (A), 2016 Preliminary Estimate (P), and 2017-2020 are forecasts (F).

The recommended escalation factor for contractor costs for 2018 –2020 is the annual per cent change in the wage rate provided by CBOC (Table 1). This recommendation is summarized in Table 2 below.

TABLE 2:

Recommended Escalation Factor for the “Contractor” Category of Costs, 2018 – 2020

	2018F	**2019F**	**2020F**
Recommended Rate (%)	2.3	2.3	2.7

3. Other Costs

Other costs represent a mix of products and services, therefore the most appropriate escalator is a broad price index. The Consumers Price Index is produced by Statistics Canada. According to the agency it is widely used as an indicator of the change in the general level of consumer prices or the rate of inflation. The CPI is widely used to adjust contracted payments, such as wages, rents, private and public pension programs (Old Age Security and the Canada Pension Plan), personal income tax deductions, and some government social payments.

Statistics Canada releases data on the CPI for Alberta monthly. The All Items CPI data are available via CANSIM in **Matrix 326-0020**, and also as **Series Number V41692327**. This series is constructed with weights determined from 2013 expenditures and with a base of 2002=100. It is available through December 2016. The series was converted to an annual series by averaging the monthly values.

Forecasts for Alberta CPI are available from several organizations. These include proprietary forecasts from the CBOC, as well as public forecasts produced by various financial institutions and the Alberta government. Public forecasts are typically available for two years. Some Banks –Bank of Nova Scotia and CIBC–have not published an Alberta CPI forecast, so they are not included in the table below. Table 3 contains the most recent Alberta CPI inflation forecast produced by the included organizations. These forecasts were released between November 2016 and February 2017. More specifically, the table includes forecasts released by Alberta Treasury and Finance on November 28, 2016, ATB Financial on November 2, 2017, Bank of Montreal (BMO) on February 17, 2017, the CBOC on November 10, 2016, National Bank on December 23, 2016, Royal Bank of Canada (RBC) in December 2016, and TD Bank (TD) on December 20, 2016. Actual historic values for the provincial inflation rate along with the average estimate for each forecast year are included in the last row of Table 3. Data for 2016 have been released by Statistics Canada and Table 3 includes the calculated growth rate for this year in the last row.

TABLE 3: Actual and Forecast Values of Alberta CPI, 2014-2020
(Annual Percent Change)

Organization	**2014A**	**2015A**	**2016P**	**2017F**	**2018F**	**2019F**	**2020F**
Alberta Treasury & Finance	2.6	1.2	1.2	1.9			
ATB Financial	2.6	1.2	1.5	2.1	1.6		
BMO	2.6	1.2	1.1	1.8	2		
CBOC	2.6	1.2	1.3	2.2	2.2	2.3	2.1
National Bank	2.6	1.2	1.3	2	2.2		
RBC	2.6	1.2	1.0	1.7	1.9		
TD	2.6	1.2	1.3	2.2	2.5		
Actual/Forecast Average	2.6	1.2	1.1	2.0	2.1	2.3	2.1

Notes: Values for 2014-2015 are actual (A), 2016 Preliminary Estimate (P), and 2017-2020 are forecasts (F).

In general a more accurate forecast is created through a consensus rather than selecting a particular outlook, so it is recommended that the average of these forecasts be used as the escalation factor. This recommendation is summarized in Table 4 below.

TABLE 4:
Recommended Escalation Factor for the "Other" Category of Costs, 2018 – 2020

	2018F	**2019F**	**2020F**
Recommended Rate (%)	2.1	2.3	2.1

4. Conclusion

This report provides information concerning historical values and forecast values of various escalators for 2018 to 2020 that are recommended for use by *EPCOR*.

Filed: 2019-01-31
EB-2018-0336
Exhibit 4
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Robert Fairholm Economic Consulting

A Corporate Partner of the Centre for Spatial Economics

Forecast Values of Escalators for 2018 to 2019

Prepared for:

EPCOR Distribution & Transmission Inc.

Prepared by:

Robert Fairholm Economic Consulting Inc.

A Corporate Partner of the C_4SE

March 3, 2017

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Executive Summary

This report provides historical and forecast values of various recommended escalators for 2018 to 2019 for use by EPCOR Distribution & Transmission Inc. which collectively is called EPCOR for this report. The recommendations are summarized in the following table:

Table ES 1: Recommended Escalators

Category	2018F	2019F
1 Contractor Costs	2.3	2.3
2 Other Costs	2.1	2.3
3 Materials Costs	2.4	2.4

1. Introduction

This report has been prepared for *EPCOR* by Robert Fairholm Economic Consulting Inc. a corporate Partner of the Centre for Spatial Economics (C_4SE). The report provides cost forecasts over the period from 2018 to 2019.

Sections 2 - 4 describe the proposed escalators and provide annual forecast values for the years 2018 – 2019. Since historical values for all concepts are not available through 2016, estimated values for the missing data are also included. In the tables that present the data, the actual data are shown in the last row of the table instead of the forecast averages in those cases where the average forecast value differs from the data subsequently released by Statistics Canada. As described in these sections, forecast values are obtained from information released by independent organizations that provide forecasts, including Financial Institutions, Alberta Treasury and Finance, The Conference Board of Canada (CBOC) and the Organization for Economic Co-operation and Development (OECD). Forecasts were released between November 2016 and February 2017.

Section 2 contains forecasts of growth in wages and salaries per employee in Alberta that are appropriate for use by EPCOR in escalating contractor costs. These can also be used as a placeholder for union escalator rates until collective agreement negotiations are complete and a settlement is reached.

Section 3 contains forecasts of the All-Items Consumer Price Index (CPI) for Alberta. The calculated inflation rate can be used directly as an escalator for costs other than materials costs and contractor costs. The value for Alberta CPI for 2016 has been released by Statistics Canada and has been used in Table 3.

Section 4 contains details of the Electric Utility Construction Price Index for Transmission Line Systems (EUCPI-T). This is a price index calculated by Statistics Canada that can be used as an escalator for materials costs. Forecast values of EUCPI-T are not available from any known forecasting organization. A forecast of EUCPI-T was calculated by first estimating its historical relationship with the Canadian CPI and then using the average CPI forecasted by a group of well-known forecasting organizations. The value for Canadian CPI for 2016 has been released by Statistics Canada and has been used in Table 5.

2. Contractor Costs

Most contractors primarily supply labour services, therefore it is recommended that the escalator for contractor costs use the forecasted growth in wages and salaries per employee in Alberta for 2018-2019. A few forecasts of various wage measures for Alberta are available. However, only the Conference Board of Canada (CBOC) produces an independent forecast of the wage rate (wages and salaries per employee) that is available publically for purchase as a separate data series. The CBOC does not produce forecasts of wage rates for individual industries. So the aggregate wage rate for the province was used instead. The most recent forecast from the CBOC prior to this report was released December 2016. The aggregate wage inflation rates are shown below in Table 1.

TABLE 1: Actual and Forecast Values of Alberta Aggregate Wage Rate

(Annual Percent Change)

	2014A	**2015A**	**2016P**	**2017F**	**2018F**	**2019F**
CBOC	4.6	-1.8	-2.9	1.5	2.3	2.3

Notes: Values for 2014-2015 are actual (A), 2016 Preliminary Estimate (P), and 2017-2019 are forecasts (F).

The recommended escalation factor for contractor costs for 2018 –2019 is the annual per cent change in the wage rate provided by CBOC (Table 1). This recommendation is summarized in Table 2 below.

TABLE 2:

Recommended Escalation Factor for the "Contractor" Category of Costs, 2018 – 2019

	2018F	**2019F**
Recommended Rate (%)	2.3	2.3

3. Other Costs

Other costs represent a mix of products and services, therefore the most appropriate escalator is a broad price index. The Consumers Price Index is produced by Statistics Canada. According to the agency it is widely used as an indicator of the change in the general level of consumer prices or the rate of inflation. The CPI is widely used to adjust contracted payments, such as wages, rents, private and public pension programs (Old Age Security and the Canada Pension Plan), personal income tax deductions, and some government social payments.

Statistics Canada releases data on the CPI for Alberta monthly. The All Items CPI data are available via CANSIM in **Matrix 326-0020**, and also as **Series Number V41692327**. This series is constructed with weights determined from 2013 expenditures and with a base of 2002=100. It is available through December 2016. The series was converted to an annual series by averaging the monthly values.

Forecasts for Alberta CPI are available from several organizations. These include proprietary forecasts from the CBOC, as well as public forecasts produced by various financial institutions and the Alberta government. Public forecasts are typically available for two years. Some Banks –Bank of Nova Scotia and CIBC–have not published an Alberta CPI forecast, so they are not included in the table below. Table 3 contains the most recent Alberta CPI inflation forecast produced by the included organizations. These forecasts were released between November 2016 and February 2017. More specifically, the table includes forecasts released by Alberta Treasury and Finance on November 28, 2016, ATB Financial on November 2, 2017, Bank of Montreal (BMO) on February 17, 2017, the CBOC on November 10, 2016, National Bank on December 23, 2016, Royal Bank of Canada (RBC) in December 2016, and TD Bank (TD) on December 20, 2016. Actual historic values for the provincial inflation rate along with the average estimate for each forecast year are included in the last row of Table 3. Data for 2016 have been released by Statistics Canada and Table 3 includes the calculated growth rate for this year in the last row.

TABLE 3: Actual and Forecast Values of Alberta CPI, 2014-2019
(Annual Percent Change)

Organization	**2014A**	**2015A**	**2016P**	**2017F**	**2018F**	**2019F**
Alberta Treasury & Finance	2.6	1.2	1.2	1.9		
ATB Financial	2.6	1.2	1.5	2.1	1.6	
BMO	2.6	1.2	1.1	1.8	2	
CBOC	2.6	1.2	1.3	2.2	2.2	2.3
National Bank	2.6	1.2	1.3	2	2.2	
RBC	2.6	1.2	1.0	1.7	1.9	
TD	2.6	1.2	1.3	2.2	2.5	
Actual/Forecast Average	2.6	1.2	1.1	2.0	2.1	2.3

Notes: Values for 2014-2015 are actual (A), 2016 Preliminary Estimate (P), and 2017-2019 are forecasts (F).

In general a more accurate forecast is created through a consensus rather than selecting a particular outlook, so it is recommended that the average of these forecasts be used as the escalation factor. This recommendation is summarized in Table 4 below.

TABLE 4:
Recommended Escalation Factor for the "Other" Category of Costs, 2018 – 2019

	2018F	**2019F**
Recommended Rate (%)	2.1	2.3

4. Materials Costs (Electric Utility Construction Price Index - Transmission)

Material costs relevant to the transmission of electricity are very specific to that industry. Industry Price Indexes are published monthly by Statistics Canada at the national level, but are not available on a provincial basis. Statistics Canada has available the Electric Utility Construction Price Indexes, for the Transmission Line Systems category (EUCPI-T) in CANSIM Matrix 327-0011 and as V735250. These data have a base 1992=100, and are available for Canada from 1956 to 2014.

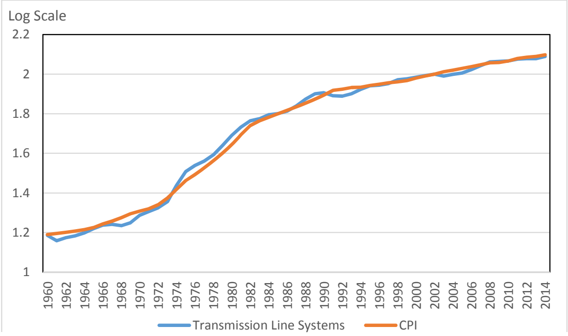
The broadest price index is for “Transmission Line Systems”. This index is an aggregation of 68 sub-categories. An examination of the sub-categories shows that no single sub-category index refers to materials or equipment alone, although several sub-categories include materials and/or equipment. Moreover, the weights used to aggregate the different sub-component indexes to form the overall price index are not published so a materials index cannot be directly calculated. Consequently, there is no direct way to calculate the relevant sub-category indexes to form an overall price index for materials. It is therefore recommended that the aggregate price index for Transmission Line Systems be used for the cost escalator as it is the most representative of total material costs.

It should be noted, however, that EUCPI-T includes factors other than materials and equipment, such as labour. Labour is explicitly identified in sub-category price indexes. Although labour costs have increased less in the period 1992 to 2014, than have other components, so their inclusion tends to reduce the overall index below what it would likely be if labour was excluded. For this reason, the use of EUCPI-T as an escalator for materials costs is likely to underestimate the rise in materials costs alone. Therefore EUCPI-T is likely to be a conservative indicator of future material cost increases.

In terms of the outlook, no known independent forecasting organization produces a forecast of EUCPI-T. In order to determine the expected outlook, the relationship between EUCPI-T and other concepts will need to be explored. If a strong relationship between the EUCPI-T and another price series can be found over the history, then this relationship and forecast values of the other price series can be used to produce forecasts of EUCPI-T.

An examination of relationship between Canadian CPI and EUCPI-T shows that there is a strong statistical relationship between the two. Figure 1 shows the price index for the EUCPI-T rebased to 2002=100 and the CPI All Items Index for Canada, 2013 Basket, 2002=100 CANSIM Matrix 326-0021. Both series are shown in log terms. It is noteworthy that the EUCPI-T tends with CPI. There can be periods during which the two can deviate, but over time the two series tend to converge again.

Figure 1: EUCPI-T and CPI Trend Together



During the 15-year period 2000-2014, the correlation between these two price indexes is 0.968, although the correlation is slightly lower (0.957) during the last five of this period (2010 to 2014), and is 0.987 over the 30 year period from 1985 to 2014. An Ordinary Least Squares (OLS) regression of EUCPI-T on the CPI (**V41693271**) indicates that there is a strong and statistically significant relationship between these two series. In order to improve explanatory power and to satisfy the various diagnostic tests that were applied to the estimated relationship, an error correction model was developed that ensures that over the long-term EUCPI-T and CPI will trend together, but that in the short-term there can be divergences between the two indexes.

Using this estimated relationship, forecast values of EUCPI-T can be estimated using the forecasts of Canadian CPI for the period of 2018-2019. Forecast values of the Canadian CPI are based on forecasts provided by various financial institutions, the OECD and the CBOC that were produced in the November 2016 to February 2017 period, as shown in Table 5. Data for 2016 have been released by Statistics Canada and Table 5 includes the calculated growth rate for this year in the last row.

TABLE 5: Actual and Forecast Values of Canadian CPI, 2014-2019

(Annual Percent Change)

Organization	**2014A**	**2015A**	**2016P**	**2017F**	**2018F**	**2019F**
BMO	1.9	1.1	1.4	2.1	2	
BNS	1.9	1.1	1.4	2.1	2.1	
CBOC	1.9	1.1	1.5	2.2	2.1	2.2
CIBC	1.9	1.1	1.4	2.1	2.4	
National Bank	1.9	1.1	1.5	1.8	2	
OECD	1.9	1.1	1.5	1.8	2.0	
RBC	1.9	1.1	1.4	2.5	2.2	
TD	1.9	1.1	1.6	2.1	1.9	2
Actual/Forecast Average	1.9	1.1	1.4	2.1	2.1	2.1

Notes: Values for 2014-2016 are actual (A), 2016 Preliminary Estimate (P), and 2017-2019 are forecasts (F).

TABLE 6: Actual and Forecast Values of EUCPI-T for 2014-2019

	2014A	**2015P**	**2016P**	**2017F**	**2018F**	**2019F**
CPI Inflation	1.9	1.1	1.4	2.1	2.1	2.1
Forecast Growth (%)	2.7	1.5	1.2	2.0	2.4	2.4

Notes: Values for 2017-2019 are forecasts (F).

The recommended escalation factors for other costs, obtained from the last row of Table 6, are presented in Table 7 below.

TABLE 7: Recommended Escalation Factor for Materials Costs for 2018-2019

	2018F	**2019F**
Recommended Rate (%)	2.4	2.4

5.0 Conclusion

This report provides information concerning historical values and forecast values of various escalators for 2018 to 2019 that are recommended for use by *EPCOR*.