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July 5, 2019

Sent By Electronic Mail, RESS Electronic Filing and Courier

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

Dear Ms. Walli:

Re: EPCOR Natural Gas Limited Partnership ("ENGLP") Southern Bruce Project EB-2018-0264 Rates Application – ENGLP Responses to Interrogatories

Pursuant to Procedural Order No. 1 in the above noted proceeding, EPCOR Natural Gas Limited Partnership ("**ENGLP**") herby submits its responses to interrogatories from OEB Staff, Enbridge Gas Inc., Industrial Gas Users Association, School Energy Coalition, Vulnerable Energy Consumers Coalition, and Anwaatin Inc.

Please do not hesitate to contact me if you have any questions.

Sincerely,

[Original signed by]

Bruce Brandell
Director, Commercial Services
EPCOR Utilities Inc.
bbrandell@epcor.com
(780) 412-3720

1.Staff.1

Reference: Exhibit 1 / Tab 2 / Schedule 1 / Pg.16

Preamble: *On December 21, 2018, EPCOR Southern Bruce received confirmation that the Southern Bruce expansion project is eligible for rate protection as available through Bill 32. On March 7, 2019 the Government of Ontario filed Ontario Regulation 24/19 Expansion of Natural Gas Distribution Systems which stated in Schedule 1 that the Southern Bruce project was eligible for up to $22.0 million funding.*

Questions:

Please clarify that the approved funding is $22.0 million and not lower.

Responses:

It is EPCOR Natural Gas Limited Partnership's ("**EPCOR's**") understanding that it has been awarded $22.0 million as a result of Ontario Regulation 24/19. EPCOR has included that value in the determination of its revenue requirement.

1.Staff.2

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

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

Questions:

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

Responses:

EPCOR has and will continue to comply with the above-noted requruiement.

1.Staff.3

Reference: Exhibit 1 / Tab 2 / Schedule 1 / Pg.22

Preamble: *EPCOR Southern Bruce has indicated that it will operate separate business units, one each for the former Natural Resource Gas Limited gas distribution system (Aylmer) and the gas distribution system in the Southern Bruce Area.*

Questions:

Please advise whether EPCOR Southern Bruce will integrate the two operations (Aylmer and Southern Bruce) and operate as a single utility in the future. If yes, please provide estimated timelines.

Responses:

EPCOR has no plans to integrate the two operations and operate as a single utility.

1.Staff.4

Reference: Exhibit 1 / Tab 2 / Schedule 1 / Pg.35

Preamble: *EPCOR Southern Bruce has indicated that the capital expenditures necessary to construct and maintain the distribution system included in EPCOR's CIP during the rate stability period total $71.832 million.*

Questions:

(a) Please provide the reference in the EB-2016-0137/38/39 applications that quantifies the capital expenditures.

(b) EPCOR Southern Bruce refers to "construct and maintain". Did the amount in the CIP include any OM&A expenditures to maintain the distribution system? If yes, please provide the forecasted amounts.

(c) What is the rate base amount at the end of year 10 based on the forecasted capital costs (as per the CIP) adjusted for other items such as depreciation, interest and grant funding?

(d) Are the cost estimates for constructing the distribution system in this application different from that estimated in the franchise competition proceeding (EB-2016- 0137/38/39)? If yes, please provide and explain the difference.

Responses:

(a) As per EB-2016-0137/0138/0139 "The OEB does not expect detailed cost information, which builds up to the revenue requirement, to be provided"[1]. As a result, the proponents were not required to quantify their respective capital expenditures. EPCOR did provide an annual and cumulative revenue requirement for the 10-year rate stability period which was used as a basis for the OEB determining the winning proponent. That revenue requirement is the revenue requirement as included in this application.

(b) The revenue requirement detailed in EPCOR's CIP did include OM&A to maintain the distribution system. As per (a) above, the OM&A costs were not quantified in the revenue requirement included in the CIP. These OM&A expenditures necessary to maintain the distribution system for the 10-year rate stability period have been included in the application in Exhibit 4, Tab 1, Schedule 2, Page 1 of 2.

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[1] EB-2016-0137/38/39, Decision on Preliminary Issues and Procedural Order No. 8, August 22, 2017, Infrastructure Specifications, page 4

(c) The rate base amount at the end of year 10 (2028) of the forecasted capital costs (as per the CIP) adjusted for other items such as depreciation, interest and grant funding is $54.442 million as included in Exhibit 2.2, Table 2.4..

(d) The cost estimates for constructing the distribution system in Exhibit 2 – Rate Base are the same as that estimated in the franchise competition proceeding (EB-2016-0137/38/39). In Exhibit 6.2.3 Foregone Costs – Change in Capital Expenditure Profile, EPCOR has detailed the impact on capital costs resulting from the expected delay in receipt of a decision on its Leave to Construct application from that assumed in the CIP. As detailed in 6.2.3 Table 6-7, the delay in the capital expenditure profile has resulted in a forecast <u>reduction</u> in the NPV of the 10 year revenue requirement of $0.460 million. For convenience, Table 6-7 is reproduced below.

Table 6-1 Change in Capital Expenditure Profile

(Thousands of Dollars)

	Description	Calculation	Col. 1 Var 1	Col. 2 2019	Col. 3 2020	Col. 4 2021	Col. 5 2022	Col. 6 2023	Col. 7 2024	Col. 8 2025	Col. 9 2026	Col. 10 2027	Col. 11 2028
Row 1	CapEx as per Original Application			(57,346)	(25,030)	(3,023)	(1,791)	(1,576)	(872)	(413)	(344)	(838)	(197)
Row 2	CapEx with the Delay			(37,906)	(26,335)	(22,897)	(1,791)	(1,576)	(872)	(413)	(344)	(838)	(197)
Row 3	Change in CapEx	R1 - R2		(19,440)	1,305	19,874	-	-	-	-	-	-	-
Row 4													
Row 5	WACC		5.82%										
Row 6	PV Factor			1.00	0.94	0.89	0.84	0.80	0.75	0.71	0.67	0.64	0.60
Row 7	PV	R3 x R6		(19,440)	1,233	17,747	-	-	-	-	-	-	-
Row 8	**NPV**	Sum of R7		**(460)**									

As a result of the delay in the construction schedule from that submitted with the CIP, the cost of construction has increased $1.739 million from $91.428 million to $93.167 million. This is offset by a delay in capital expenditures, resulting in the net reduction in the NPV of capital costs of $0.460 million. This increase is reflected in the above mentioned reduction in the NPV of the 10-year revenue requirement.

1.Staff.5

Reference: Exhibit 1 / Tab 2 / Schedule 1 / Pg.62

Preamble: *EPCOR Southern Bruce has proposed a scorecard to measure and monitor performance over the 10-year rate stability period. The proposed scorecard is informed by Ontario electricity distributors' scorecard and the scorecard proposed by Enbridge Gas Inc. in the amalgamation application of Enbridge Gas Distribution and Union Gas Limited.*

Questions:

In the OEB's amalgamation decision (EB-2017-0306/0307) issued on August 30, 2018, the OEB on page 52 directed Enbridge Gas Inc. to add total cost per customer and total cost per km. of distribution pipeline to the scorecard. Please confirm if EPCOR Southern Bruce agrees to add the above two metrics to its proposed scorecard.

Responses:

Confirmed. EPCOR Southern Bruce agrees to add 'total cost per customer per year' and 'total cost per km of distribution pipe per year' to its proposed scorecard. A revised proposed scorecard has been provided as 1.Staff.5 Attachment 1.

South Bruce Performance Scorecard

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Reconnection response time (# of days to reconnect a customer)	*# of reconnections completed within 2 business days/# of reconnections completed*
		Scheduled appointments met on time (appointments met within designated time period)	*# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month*
		Telephone calls answered on time (call answering service level)	*# of calls answered within 30 seconds / # of calls received*
	Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response)	*# of complaints requiring response within 10 days / # of complaints requiring a written response*
		Billing accuracy	*Number of manual checks done as per quality assurance program, for excessively high or low usage.*
		Abandon Rate (# of calls abandon rate)	*# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent*
		Time to reschedule missed appointments	*% of rescheduled work within 2 hours of the end of the original appointment time*
Operational Effectiveness	Safety, system reliability and asset management	Meter Reading Performance	*# of meters with no read for 4 consecutive months / # of active meters to be read*
		% of Emergency Calls Responded within One Hour	*# of emergency calls responded within 60 minutes / # of emergency calls*
		Damages	*Third party line breaks per 1,000 locate requests*

Public Policy Responsiveness	Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system	*(# of communities serviced by system/# of communities committed to in CIP)*
		$/m3 cost to deliver natural gas	*Average $/m3 determined in CIP (as adjusted) – Actual average $/m3*
		Customer years	*Average customer years / Customer years as determined in CIP*
		Cumulative volume	*Actual cumulative volume / Cumulative volume as determined in CIP*
Financial Performance	Financial Ratios	Current Ratio	
		Debt Ratio	
		Debt to Equity Ratio	
		Interest Coverage	
		Financial Statement Return on Assets	
		Financial Statement Return on Equity	
		Total Cost per Customer per year	
		Total Cost per km of distribution pipe per year	

1.Staff.6

Reference: Exhibit 1 / Tab 3 / Schedule 1 / Pg.39

Preamble: *In the survey, respondents were asked how likely they were to convert to natural gas within the first year if a $400 to $500 grant was available to help with conversion costs. The survey revealed that 87% would likely convert within the first year if a grant was available.*

Questions:

(a) Is EPCOR Southern Bruce considering providing a grant to potential customers if the forecasted customer attachments are not attained? If yes, please provide details.

Responses:

(a) At this time, EPCOR is not considering a grant to potential customers if forecasted customer attachments are not attained.

2.Staff.7

Reference: Exhibit 2 / Tab 1 / Schedule 1 / Pg.4 / Table 2-4

Preamble: *From Table 2-4, the Capital Expenditure in 2025 is $255,000, 2026 is $185,000, 2027 is $667,000 and 2028 is $33,000.*

Questions:

Please explain the substantive increase in capital expenditure for 2027.

Responses:

The increase in capital expenditure is due to the replacement of vehicles that are forecast to be initially acquired in 2019.

2.Staff.8

Reference: Exhibit 2 / Tab1 / Schedule 1 / Pg.5

Preamble: *As a new utility, EPCOR Southern Bruce has the advantage of capturing and documenting the required information in a manner consistent with modern utility practices to better inform future decision making.*

Questions:

(a) Please provide a brief summary of the best practices that EPCOR Southern Bruce intends to implement to ensure that appropriate risk management practices are in place and there is an effective maintenance, record keeping and monitoring strategy.

(b) What kind of monitoring practices does EPCOR Southern Bruce intend to implement for the steel pipelines?

Responses:

(a) As stated in the Utility System Plan, EPCOR will implement an asset management framework consistent with ISO 55000 Standards for Asset Management and the more specific requirements of CSA Z662 Oil and Gas Pipeline Systems standards (CSA Z662). At its foundation, the asset management process is risk-based and founded on the principles of continuous improvement.

EPCOR intends to leverage the Elements utility management software for asset management in the new utility. As-built GIS data surveyed during construction and asset information (e.g. pipeline materials, MAOP, valves and components) will be captured in the system. Maintenance monitoring and repair activities will be planned, scheduled and tracked in the system going forward. Through this, asset information will be readily available to field and office staff.

(b) As stated in the Utility System Plan, EPCOR will implement condition monitoring practices consistent with industry accepted practices and the requirements of a System Integrity Management Program under CSA Z662. Routine monitoring will include regular leak surveys, pipe-to-soil potential surveys for assessing the performance of cathodic protection system and pipeline coating systems, and depth-of-cover surveys. The steel pipelines are designed to allow for the use of smart pigging technology for inline inspection.

2.Staff.9

Reference: Exhibit 2 / Tab 1 / Schedule 1 / Pg.15 / Table 2-6

Preamble: *EPCOR Southern Bruce is proposing to capitalize one FTE for the entire rate stability period. Table 2-6 indicates a significant drop of direct capital cost starting from 2025 through to 2028 (with the exception of 2027).*

Questions:

Please provide additional information on how the FTE will be used as capitalized overhead, as this FTE accounts for 38%-82% of capital expenditure and overheads in the last three of the four years of the rate stability period.

Responses:

As a new utility, EPCOR is expected to experience a rapidly growing connection count during the 10-year rate stability period. Activities to acquire customers, including customer contact, installation of plant infrastructure and meters require some level of effort from EPCOR's operating staff. This FTE will support customer acquisition activities throughout the 10-year rate stability period, in particular the last 4 years where EPCOR's construction contractor is expected to have completed their work. As work of the construction contractor concludes the responsibility for EPCOR's operator operational staff to acquire and connect new customers is expected to increase. These costs include asset expenses, however are primarily driven by the cost of the FTE executing and installing the connection.

EPCOR notes that operating and capitalized expenses were forecasted for the 10-year period as part of the CIP process, these values support the revenue requirement that EPCOR included in its CIP.

3.Staff.10

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

Preamble: *EPCOR Southern Bruce has proposed to obtain service from Enbridge Gas (formerly Union Gas Limited) under a new M17 rate class. In its evidence EPCOR Southern Bruce has noted that if the rates included in any OEB approved M17 service are different from those included in Enbridge Gas' application, or if EPCOR Southern Bruce is able to access an alternative service, such as M9, that would include storage, it will update the relevant elements of this application.*

Questions:

(a) Please provide EPCOR Southern Bruce's proposal in the event that the OEB first approves the cost consequences as per the proposed M17 rate in this application and the actual service approved later is different from the one approved in this application. In other words, what would be the proposed remedy to capture the difference in timing of the two applications (the current rate application and the M17 rates application)?

(b) What would be the difference in upstream charges if EPCOR Southern Bruce is able to obtain M9 service as opposed to the M17 service currently assumed in this application?

Responses:

(a) If the OEB first approves the cost consequences as per the proposed M17 rate in this application and the actual service approved later is different from the one approved in this application, EPCOR proposes to address those cost consequences as follows:

Any impact to the annual revenue requirement resulting from a difference in the contribution in aid of construction (CIAC) required to be paid to Enbridge Gas would be recorded annually in the proposed Contribution in Aid of Construction Variance Account ("CIACVA"). EPCOR will bring the balance in this account forward for disposition on an annual basis, at which time it will propose a methodology and timing for disposition that aligns with customers' use of the capacity and EPCOR's rate smoothing objectives. In its cost of service application for rates commencing 2029, EPCOR will propose to adjust its rate base to record the depreciated difference in capital contribution so as to appropriately reflect the finalized capital contribution paid in its rate base and revenue requirement commencing 2029. For additional details regarding the CIACVA see the revised draft accounting order in 9.Staff.39 Attachment 1.

For any impact on the remaining upstream charges (including Upstream Recovery Charge and the Transportation and Storage Charge), EPCOR proposes to record and dispose of any differences associated with these costs through the proposed Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11") and the proposed Transportation Variance Account for Rate 16 ("TVA Rate 16") as outlined in the revised draft accounting orders provided in 9.Staff.39 Attachment 1. EPCOR proposes to bring forward the balances in the S&TVA Rates 1, 6 & 11 and TVA Rate 16 accounts for disposition after the maximum balance in these accounts has been reached which is expected to occur in 2024. The balance in these accounts together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas. When the balance in these accounts are brought forward for disposition, EPCOR will also bring forward a proposal for the treatment of the variances related to upstream costs for customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would be more appropriately brought forward for disposition on an annual basis and recovered over a shorter term.

(b) The difference in upstream charges if EPCOR is able to obtain M9 services as opposed to the M17 service currently assumed in the application is summarized in Table OEB 3.Staff.10 – 1 below. The calculation is based on CIP customer count, volume and capacity, Enbridge's M9 and M17 tariffs effective January 1, 2019 and escalated at inflation rate of 1.27% annually. Load balancing administrative costs are based on $0.03 per GJ in 2018 dollars. The conversation of GJ per m3 of natural gas volume is 0.03889, which reflects the conversion rate used by Enbridge's Union South service territory affective April 1, 2018. Storage cost is based on information from the gas supply plan.

EPCOR notes that the M9 and proposed M17 services are fundamentally different. M9 is a fully bundled, cost-based service which is a no-notice service and includes transportation, seasonal storage, and daily load, whereas M17 is transportation only service, requiring daily nominations and the remaining storage and balancing components and must be acquired at market rates. Since there are both variable and demand-based components of the market-based services <u>there could be additional charges incurred to accommodate the seasonal and daily balancing</u>. EPCOR is not proposing to provide any seasonal storage services for Rate 16 under a M17 scenario. Rate 16 customers therefore must acquire any seasonal storage they may require. <u>Those charges could be material and are not reflected in the cost comparison below</u>.

Table OEB 3.Staff.10 -1

Cost Difference M17 vs M9 Tariff

(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1	Enbridge Gas M17 Cost	84	505	514	523	531	539	546	553	560	567
Row 2	add Storage Cost[1]	52	94	133	160	179	191	196	202	207	210
Row 3	add Load Balancing Admin.	6	31	37	41	44	46	47	48	48	49
Row 4	less Enbridge Gas M9 Charge	-110	-662	-678	-693	-706	-717	-727	-737	-746	-756
Row 5	Difference	31	-31	6	31	48	58	62	66	69	70

[1] Does not include storage costs for Rate 16 customers as under M17 they would be acquiring their own storage. These costs could be material.

4.Staff.11

Reference: Ref: Exhibit 4 / Tab 1 / Schedule 1 / Pg.18

Preamble: *EPCOR Southern Bruce anticipates it will require seven FTEs for full operations.*

Questions:

Please explain how seven FTEs are sufficient to manage a utility with over 5,000 customers.

Responses:

As detailed below, EPCOR's use of its shared service model, combined with the necessary locate operating staff, allows it to manage and operate a utility in an efficient and effective manner.

EPCOR anticipates it will employ 2 gas fitters, 2 maintenance staff and one foreman for a total of 5 full time field staff dedicated to its Southern Bruce operations. By comparison, there are 7 field operations staff in EPCOR's larger (9,000 customers) Aylmer operation —4 Field Technicians, 1 Utility Service Technician, 1 Construction Lead, and 1 Field Construction Technician. In addition to field staff, Southern Bruce will employ two full time administrative staff dedicated to customer service requirements for a total of 7 FTE's.

EPCOR Southern Bruce is also expected to receive shared services from the Aylmer division. These services will be charged by Aylmer to Southern Bruce as OM&A offsets, in the form of 0.25 FTE for Administration, and 0.25 FTE for General Manager; the balance of these positions (0.75 FTE respectively), are funded by the Aylmer division. This is consistent with the forecasts shared as part of the ENGLP 2020-2024 Cost of Service rate filing.[1]

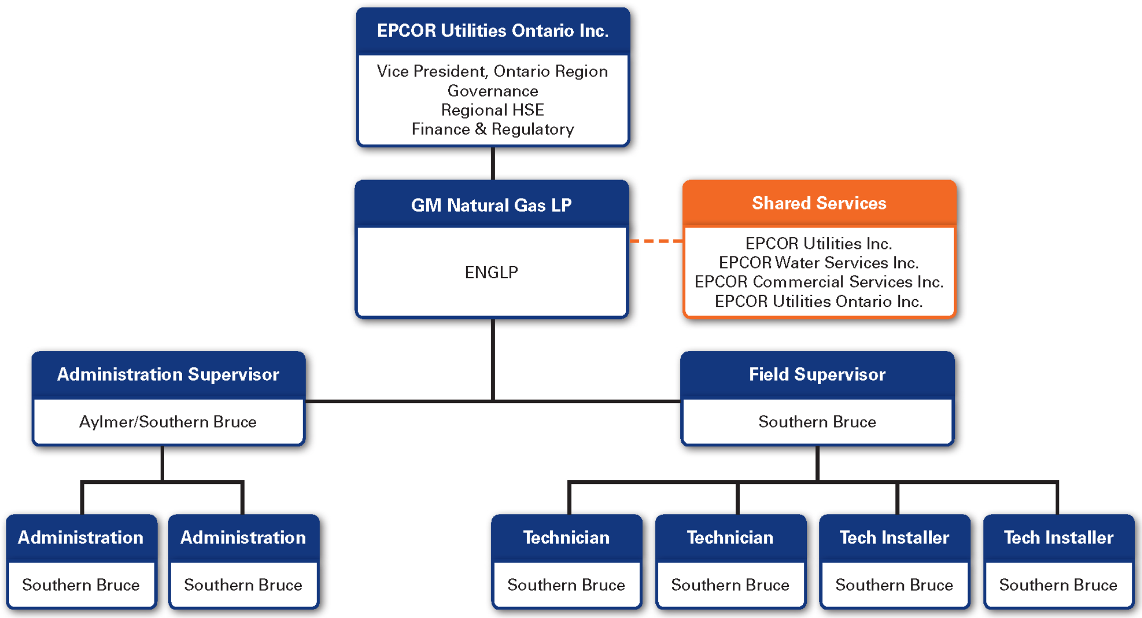
EPCOR has contracted with AECON to complete construction of the Southern Bruce project, including setting the meter. These resources partially address the requirement for construction employees to be directly employed by Southern Bruce such as the two full time construction resources employed Aylmer. Finally, given that the Southern Bruce system is a new build the utility does not anticipate certain issues that more mature utilities with older asset profiles experience, e.g. leakage, main relocations.

EPCOR currently deploys a shared services model for corporate functions including Treasury, Public & Government Affairs, Infrastructure Services, Legal and Supply Chain Management. This shared service model is summarized in the organization chart

[1] EB-2018-0336, Exhibit 4, 4.3.3.1, paras 10 and 30.

reproduced below from Exhibit 1, Tab 2, Schedule 1, page 23 and detailed in Exhibit 4.3.3.2.

Figure 1-2: Organizational Chart of EPCOR's Southern Bruce Business Unit



EPCOR Ontario will provide management oversight, regulatory, finance and Health, Safety and Environment (HS&E) functions and Gas Supply strategy. These functions also support EPCOR's other Ontario based businesses.

EPCOR is currently finalizing its gas transportation and storage requirements with Enbridge and other third parties. The complexity of the gas supply management portfolio may require further resources. The costs of these resources are included in the Upstream Charges of EPCOR's proposed tariff.

Additional details of the shared services allocation methodology and allocations which leverages the strength of other EPCOR companies are explained in even greater detail as part of OEB 4.Staff-14.

4.Staff.12

Reference: Exhibit 4 / Tab 1 / Schedule 1 / Pg.20

Preamble: *EPCOR Southern Bruce has noted that in the initial years, capitalized salaries are higher to account for system construction and growth.*

Questions:

Please provide the quantum and percentage (as compared to total) of all OM&A type expenses that have been capitalized in the first three years of service.

Responses:

OM&A expenses that have been capitalized in the first three years of service are as summarized in the table below.

Table OEB 4.Staff.12-1
Capitalized OM&A Expenses

			Col. 1	Col. 2	Col. 3
	Operating Expense	Calculation	2019	2020	2021
Row 1	O&M Expense[1]		894	2,128	2,189
Row 2	O&M Expense Capitalized[2]		-338	-685	-474
Row 3	Capitalization %	-R2 / R1	37.8%	32.2%	21.6%

[1] Exhibit 4 Tab 1 Schedule 2 Table "OM&A Budget – Nominal Dollars" Rows 1 -10
[2] Exhibit 4 Tab 1 Schedule 2 Table "OM&A Budget – Nominal Dollars" Row 11

4.Staff.13

Reference: Exhibit 4 / Tab 1 / Schedule 1 / Pg.20

Preamble: *EPCOR Southern Bruce has forecasted OM&A levels from 2019 to 2023 in accordance with Procedural Order No. 8 in EB-2016-0137/38/39 and the common assumptions agreed to by the parties during the CIP process.*

Questions:

(a) Please confirm that EPCOR Southern Bruce has used an escalator of 1.27% per annum to calculate forecasted OM&A costs during the rate stability period.

(b) Would EPCOR Southern Bruce's OM&A costs requested in its next rebasing application (Year 11) be impacted if it uses an escalator of 1.27% versus actual inflation? If yes, please provide the estimated impact in Year 11.

Responses:

(a) EPCOR confirms that it has used an escalator of 1.27% per annum to calculate forecasted OM&A costs during the rate stability period. This was one of the common assumptions that allowed the OEB to directly compare the proponents CIPs.

(b) EPCOR expects that it's next rebasing application (year 11) will be a typical cost of service application. Therefore, OM&A costs requested in that rebasing application will reflect the actual OM&A costs the utility is prudently incurring rather than a value that equals the CIP OM&A costs that have been either escalated or inflated.

4.Staff.14

Reference: Exhibit 4 / Tab 1 / Schedule 1 / Pgs.22-55

Preamble: *EPCOR Southern Bruce will receive shared services from its parent corporation EPCOR Utilities Inc. and its affiliate companies.*

Questions:

(a) Please provide a breakdown of Shared Service and Corporate Costs for the years 2020 to 2023 and provide the percentage allocation to the Southern Bruce operations.

(b) Please confirm that any corporate/shared services costs allocated to the Southern Bruce operations for 2019 and beyond, does not include historic costs related to developing the CIP or providing support for the franchise competition proceeding (EB-2016-0137/38/39).

(c) Human Resources, Supply Chain Management and Public & Government Affairs services will be provided by both EPCOR Utilities Inc. and EPCOR Water Services Inc. Please explain why a small utility like EPCOR Southern Bruce requires a range of sophisticated and duplicative services from two entities.

(d) EPCOR Utilities Inc. and the affiliates aim to provide a range of services to the Southern Bruce operations. Some of these include management development program, treasury, labour relations, mailroom services, security and public & government affairs. Please explain how some of the services can be reasonably provided considering that the providers are based in Alberta.

(e) Please confirm that the costs allocated for services provided by the parent and other affiliates is not merely a cost allocation exercise but reflect actual costs that will be incurred for providing services that are truly required by EPCOR Southern Bruce.

(f) Will EPCOR Southern Bruce submit a corporate cost allocation study as part its next rebasing application (Year 11)? If no, why not?

Responses:

(a) A breakdown of the forecasted Shared Services and Corporate Costs and the associated percentage allocation for EPCOR Southern Bruce for services provided by EPCOR Utilities Inc. (EUI), EPCOR Water Services Inc. (EWSI), EPCOR Commercial Services Inc. (ECSI), EPCOR Ontario Utilities Inc. (EOUI), for the years 2020 through 2023, are provided in the tables below. The amounts provided in the Application were based on then-current forecasted amounts and assumptions of how the services would be provided. The amounts in the tables below are based on the most current information and assumptions and therefore do not directly align with amounts provided in the Application. In addition to changes in the forecasted costs of some of the underlying services, the EPCOR Water Services Inc. (EWSI) costs are no longer allocated based on the allocators as outlined in the Application but rather are direct charged based on estimated time spent in support of the Southern Bruce operations. In addition, as described in the Application, Finance services were to be provided from EUI, ECSI and EOUI. EPCOR Electricity Distribution Ontario (EEDO) will be providing the Finance services currently showing as being provided by EOUI in the Application and in the tables below.

Table 4.Staff.14 – 1
EUI Corporate Shared Services Costs Allocated to EPCOR Southern Bruce 2020-2023
(Nominal $)

		A	B	C	D
	Function	**2020 F**	**2021 F**	**2022 F**	**2023 F**
	EUI				
1	Supply Chain Management	7,722,178	7,820,250	7,919,567	8,020,145
2	Human Resources	8,170,483	8,274,248	8,379,331	8,485,749
3	Information Systems	11,796,177	11,945,988	12,097,703	12,251,343
4	Corporate Finance Services	4,980,423	5,043,674	5,107,729	5,172,597
5	Executive and Executive Assistants	3,150,533	3,190,545	3,231,065	3,272,099
6	Treasury	1,948,864	1,973,615	1,998,679	2,024,063
7	Board	1,519,621	1,538,920	1,558,464	1,578,257
8	Audit and Risk Management	1,948,520	1,973,266	1,998,327	2,023,705
9	Public and Government Affairs	6,351,807	6,432,475	6,514,167	6,596,897
10	Legal Services	2,687,550	2,721,682	2,756,247	2,791,252
11	Health Safety & Environment	791,876	801,933	812,117	822,431
12	Incentive Compensation	5,453,806	5,523,069	5,593,212	5,664,246
13	**Total EUI**	**56,521,838**	**57,239,665**	**57,966,609**	**58,702,785**
	EPCOR Southern Bruce				
14	Supply Chain Management	19,506	22,818	25,162	27,130
15	Human Resources	12,342	14,438	15,921	17,166
16	Information Systems	22,869	26,752	29,500	31,808
17	Corporate Finance Services	15,349	17,956	19,800	21,349
18	Executive and Executive Assistants	8,522	9,969	10,992	11,852
19	Treasury	4,310	5,042	5,560	5,995
20	Board	4,609	5,392	5,946	6,411
21	Audit and Risk Management	5,868	6,864	7,569	8,162
22	Public and Government Affairs	50,067	58,568	64,583	69,636
23	Legal Services	7,269	8,504	9,377	10,111
24	Health Safety & Environment	1,173	1,372	1,513	1,631
25	Incentive Compensation	16,097	18,830	20,764	22,388
26	**Total EPCOR Southern Bruce**	**167,981**	**196,506**	**216,687**	**233,640**

	% Allocation to EPCOR Southern Bruce				
27	Supply Chain Management	0.25%	0.29%	0.32%	0.34%
28	Human Resources	0.15%	0.17%	0.19%	0.20%
29	Information Systems	0.19%	0.22%	0.24%	0.26%
30	Corporate Finance Services	0.31%	0.36%	0.39%	0.41%
31	Executive and Executive Assistants	0.27%	0.31%	0.34%	0.36%
32	Treasury	0.22%	0.26%	0.28%	0.30%
33	Board	0.30%	0.35%	0.38%	0.41%
34	Audit and Risk Management	0.30%	0.35%	0.38%	0.40%
35	Public and Government Affairs	0.79%	0.91%	0.99%	1.06%
36	Legal Services	0.27%	0.31%	0.34%	0.36%
37	Health Safety & Environment	0.15%	0.17%	0.19%	0.20%
38	Incentive Compensation	0.30%	0.34%	0.37%	0.40%
39	**Total % allocated to EPCOR Southern Bruce**	**0.30%**	**0.34%**	**0.37%**	**0.40%**

Table 4.Staff.14 – 2
EUI Corporate Asset Usage Fees Allocated to EPCOR Southern Bruce 2020-2023
(Nominal $)

		A	B	C	D
	Function	**2020 F**	**2021 F**	**2022 F**	**2023 F**
	EUI				
1	Disaster Recovery Leasehold	296,826	300,596	304,413	308,279
2	Equipment - EPCOR Tower	924,376	936,116	948,004	960,044
3	Furniture and Fixtures	517,685	524,260	530,918	537,660
4	Human Resource System	530,428	537,164	543,986	550,895
5	Information Systems	14,521,954	14,706,383	14,893,154	15,082,297
6	Leasehold Improvement - EPCOR Tower	1,149,287	1,163,883	1,178,664	1,193,633
7	Financial Systems	2,419,400	2,450,126	2,481,243	2,512,755
8	Vehicles	4,546	4,604	4,662	4,721
9	**Total EUI**	**20,364,502**	**20,623,131**	**20,885,045**	**21,150,285**
	EPCOR Southern Bruce				
10	Disaster Recovery Leasehold	440	515	568	612
11	Equipment - EPCOR Tower	2,309	2,702	2,979	3,212
12	Furniture and Fixtures	1,173	1,372	1,513	1,631
13	Human Resource System	749	877	967	1,042
14	Information Systems	26,718	31,255	34,465	37,161
15	Leasehold Improvement - EPCOR Tower	2,130	2,492	2,748	2,963
16	Financial Systems	4,644	5,432	5,990	6,459
17	Vehicles	13	15	17	18
18	**EPCOR Southern Bruce Total**	**38,177**	**44,660**	**49,246**	**53,099**
	% Allocation to EPCOR Southern Bruce				
19	Disaster Recovery Leasehold	0.15%	0.17%	0.19%	0.20%
20	Equipment - EPCOR Tower	0.25%	0.29%	0.31%	0.33%
21	Furniture and Fixtures	0.23%	0.26%	0.28%	0.30%
22	Human Resource System	0.14%	0.16%	0.18%	0.19%
23	Information Systems	0.18%	0.21%	0.23%	0.25%
24	Leasehold Improvement - EPCOR Tower	0.19%	0.21%	0.23%	0.25%
25	Financial Systems	0.19%	0.22%	0.24%	0.26%
26	Vehicles	0.29%	0.33%	0.36%	0.39%
27	**Total % allocated to EPCOR Southern Bruce**	**0.19%**	**0.22%**	**0.24%**	**0.25%**

Table 4.Staff.14 – 3
Directly Assigned Corporate Services Costs to EPCOR Southern Bruce 2020-2023
(Nominal $)

	Function	A 2020 F	B 2021 F	C 2022 F	D 2023 F
	EUI				
1	IS Application Support	8,753,313	8,864,480	8,977,059	9,091,068
2	IS desktops, printers and network support	8,284,086	8,389,294	8,495,838	8,603,735
3	Supply Chain Management - Space Rent	3,668,601	3,715,192	3,762,375	3,810,157
4	Supply Chain Management - Security	69,830	70,717	71,615	72,524
5	Health & Safety	150,258	152,166	154,099	156,056
6	**Total EUI**	**20,926,088**	**21,191,849**	**21,460,986**	**21,733,540**
	EPCOR Southern Bruce				
7	IS Application Support	24,354	28,490	31,415	33,873
8	IS desktops, printers and network support	25,348	29,652	32,698	35,256
9	Supply Chain Management - Space Rent	0	0	0	0
10	Supply Chain Management - Security	0	0	0	0
11	Health & Safety	0	0	0	0
12	**EPCOR Southern Bruce Total**	**49,702**	**58,142**	**64,113**	**69,129**
	% Allocation to EPCOR Southern Bruce				
13	IS Application Support	0.28%	0.32%	0.35%	0.37%
14	IS desktops, printers and network support	0.31%	0.35%	0.38%	0.41%
15	Supply Chain Management - Space Rent	0.00%	0.00%	0.00%	0.00%
16	Supply Chain Management - Security	0.00%	0.00%	0.00%	0.00%
17	Health & Safety	0.00%	0.00%	0.00%	0.00%
18	**Total % allocated to EPCOR Southern Bruce**	**0.24%**	**0.27%**	**0.30%**	**0.32%**

Table 4.Staff.14 – 4
EWSI Shared Services Costs Allocated to EPCOR Southern Bruce 2020-2023
(Nominal $)

		A	B	C	D
	Shared Service	**2020 F**	**2021 F**	**2022 F**	**2023 F**
	EWSI				
1	SCM	1,026,891	1,039,933	1,053,140	1,066,515
2	P&GA	947,755	959,791	971,981	984,325
3	HR	623,758	631,680	639,702	647,826
4	Training and Development	2,728,608	2,763,261	2,798,355	2,833,894
5	PMO	389,265	394,209	399,215	404,285
6	Other Services	10,460,969	10,593,823	10,728,365	10,864,615
7	**Total EWSI**	16,177,246	16,382,697	16,590,757	16,801,460
	EPCOR Southern Bruce				
8	SCM	3,340	3,907	4,308	4,645
9	P&GA	-	-	-	-
10	HR	35,256	41,243	45,479	49,037
11	Training and Development	2,728	3,191	3,519	3,794
12	PMO	4,111	4,809	5,303	5,718
14	**Total EPCOR Southern Bruce**	**45,435**	**53,150**	**58,608**	**63,194**
	% Allocation to EPCOR Southern Bruce				
15	SCM	0.33%	0.38%	0.41%	0.44%
16	P&GA	-	-	-	-
17	HR	5.65%	6.53%	7.11%	7.57%
18	Training and Development	0.10%	0.12%	0.13%	0.13%
19	PMO	1.06%	1.22%	1.33%	1.41%
20	**Total % allocated to EPCOR Southern Bruce**	**0.28%**	**0.32%**	**0.35%**	**0.38%**

Table 4.Staff.14 – 5
ECSI Shared Services Costs Allocated to EPCOR Southern Bruce 2020-2023
(Nominal $)

		A	B	C	D
	Shared Service	**2020 F**	**2021 F**	**2022 F**	**2023 F**
	ECSI				
1	Management Oversight	323,820	327,933	332,097	336,315
2	Finance	246,720	249,853	253,026	256,240
3	**Total ECSI**	**570,540**	**577,786**	**585,124**	**592,555**
	EPCOR Southern Bruce				
4	Management Oversight	36,380	42,557	46,928	50,599
5	Finance	38,347	44,859	49,466	53,336
6	**Total EPCOR Southern Bruce**	**74,727**	**87,416**	**96,394**	**103,935**
	% Allocation to EPCOR Southern Bruce				
7	Management Oversight	11.2%	13.0%	14.1%	15.0%
8	Finance	15.5%	18.0%	19.5%	20.8%
9	**Total % allocated to EPCOR Southern Bruce**	**13.1%**	**15.1%**	**16.5%**	**17.5%**

Table 4.Staff.14 – 6
EOUI Shared Services Costs Allocated to EPCOR Southern Bruce 2020-2023
(Nominal $)

	Shared Service	A 2020 F	B 2021 F	C 2022 F	D 2023 F
	EOUI				
1	Management Oversight	205,600	208,211	210,855	213,533
2	Finance	154,200	156,158	158,142	160,150
3	Regulatory	308,400	312,317	316,283	320,300
4	HSE	154,200	156,158	158,142	160,150
5	Board of Directors	12,336	12,493	12,651	12,812
6	Office Facilities	179,461	181,740	184,048	186,386
7	**Total EOUI**	1,014,197	1,027,077	1,040,121	1,053,331
	EPCOR Southern Bruce				
8	Management Oversight	42,608	49,843	54,962	59,262
9	Finance	31,956	37,382	41,221	44,447
10	Regulatory	63,912	74,765	82,443	88,893
11	HSE	13,172	15,408	16,991	18,320
12	Board of Directors	4,366	5,107	5,631	6,072
13	Office Facilities	18,596	21,754	23,988	25,864
14	**Total EPCOR Southern Bruce**	**174,609**	**204,259**	**225,236**	**242,858**
	% Allocation to EPCOR Southern Bruce				
15	Management Oversight	20.72%	23.94%	26.07%	27.75%
16	Finance	20.72%	23.94%	26.07%	27.75%
17	Regulatory	20.72%	23.94%	26.07%	27.75%
18	HSE	8.54%	9.87%	10.74%	11.44%
19	Board of Directors	35.39%	40.88%	44.51%	47.39%
20	Office Facilities	10.36%	11.97%	13.03%	13.88%
21	**% Allocation to ENGLP**	**17.2%**	**19.9%**	**21.7%**	**23.1%**

(b) Confirmed, the corporate/shared services costs allocated to the Southern Bruce operations for 2019 and beyond, do not include historic costs related to developing the CIP or providing support for the franchise competition proceeding (EB-2016-0137/38/39)

(c) The services listed are required to support the operations in the provision of safe and reliable natural gas service to its customers. Regardless of the utility size, the utility is still required to comply with all regulatory requirements and ensure the development, implementation and maintenance of programs in support of the operations and regulatory requirements The employees of EPCOR Southern Bruce will not have the expertise in these areas and will require the support of the Shared Services for these areas to for example:

- Develop and maintain ongoing customer engagement and outreach,
- Develop and maintain competitive employee compensation and benefits packages,
- Administration of employee records, payroll and benefits,
- Ensure compliance with employment legislation and implement new initiatives as required,
- Disaster recovery planning to ensure the continuity of critical systems in the event of a disaster,
- Administer the procurement of services and setting and managing standards of products and services.

In general, the services provided from EPCOR Utilities Inc. (EUI) are at the corporate level and relate to developing and maintaining standardized corporate policies and procedures as well as providing services to all the corporate departments that support EPCOR Southern Bruce. Services provided by EWSI are more direct and specific to the day-to day operations of EPCOR Southern Bruce. No duplication of services will occur as each affiliate is providing a different service.

(d) The provision of the shared services to a location that is remote to the service provider is common within the EUI groups of companies as the majority of the service providers are located in Edmonton and EUI and its subsidiaries have a number of operations outside of Edmonton including in Southern and Northern Alberta, British Columbia, Saskatchewan and Aylmer, Ontario.

The location of the utility in relation to the service providers does not impact their ability to provide the services as the utility is connected to the service providers through EUI's information system network which facilitates the provisions of these services from Alberta. The service providers are able to deliver the majority of the services remotely working closely with the utility's management, operations and administrative resources. As required, the service providers will travel to Southern Bruce to provide support that cannot be provided remotely.

Mailroom services specifically, located in Edmonton, processes incoming and outgoing internal mail between all EUI locations (including EPCOR Southern Bruce) and ensures that any external mail through outsourced couriers and Canada Post addressed to EPCOR's main office is routed to the proper location.

(e) Confirmed. The costs allocated for services provided by EUI and other affiliates are not merely a cost allocation exercise but reflect the fully allocated actual costs associated with providing services that are required by EPCOR Southern Bruce for the provision of natural gas service to its customers.

(f) In advance of the next rebasing application, EPCOR Southern Bruce will assess whether there is need to complete and submit a corporate cost allocation study with that application, based on the information and circumstances at the time.

4.Staff.15

Reference: Exhibit 4 / Tab 1 / Schedule 1 / Pgs.27-28

Preamble: *EPCOR Southern Bruce has included costs of EPCOR Utilities Inc. Board of Directors in its corporate costs.*

Questions:

(a) Please provide the amount allocated to EPCOR Southern Bruce for services provided by EPCOR Utilities Inc. Board of Directors for the years 2019 to 2023.

(b) Please explain why the parent's Board of Directors' costs should be allocated to EPCOR Southern Bruce considering that the Board of Directors of the parent company are protecting shareholder interests and compensated through the company's earnings.

(c) Please confirm if any costs related to Treasury Operations has been allocated to the Southern Bruce operations. If yes, please provide the quantum and the type of treasury services that the Southern Bruce operations would require.

Responses:

(a) The forecasted allocation to EPCOR Southern Bruce for services provided by EPCOR Utilities Inc. Board of Directors for the years 2019 through 2023 are provided in the Table 4.Staff.15-1 below. As noted in 4.Staff.14 (a) these numbers are based on the most current information and assumptions.

Table 4.Staff.15 – 1
EUI Board of Directors Costs Allocated to EPCOR Southern Bruce 2019-2023
(Nominal $)

	A **2019 F**	B **2020 F**	C **2021 F**	D **2022 F**	E **2023 F**
1 Board Costs	1,994	4,609	5,392	5,946	6,411

(b) The EPCOR Utilities Inc. ("EUI") Board of Directors, and its committees, ("EUI Board") not only protects the interest of the shareholder but it provides governance functions that set the overall objectives, strategic direction, and policies for the EPCOR group of companies, including EPCOR Southern Bruce. The functions of the EUI Board include:

- Establishing the strategic objectives and direction of EPCOR group of companies.
- Reviewing and approving corporate-wide policies.
- Providing direction and oversight to safeguard and maintain the long-term value of corporate assets.
- Reviewing and approving significant financial matters for the EPCOR group, including the provision of significant internal financing to subsidiaries.

- Approving EUI consolidated capital and operating budgets, to meet the objectives established in the EUI group's strategic plan.
- Appointing the auditors of and approving EUI's annual consolidated financial statements.
- Approving corporate-wide compensation policies and programs.
- Evaluating and assessing corporate-wide performance against strategic, operating and capital plans.
- Understanding and monitoring corporate-wide business risks.

The functions served by the EUI Board provide significant benefit to EPCOR Southern Bruce and serve functions that are necessary for its operations. Without the EUI Board EPCOR Southern Bruce would incur significantly higher costs than the nominal amounts noted in (a) above in order to access the breadth of expertise provided by the EUI Board and implement these functions at the utility level. Given that the functions served by the EUI Board benefit all of EUI's subsidiaries, including EPCOR Southern Bruce, it is appropriate that EPCOR Southern Bruce covers a share of these costs.

(c) Confirmed, $2,594 of costs related to Treasury Operations are forecasted to be allocated to EPCOR Southern Bruce operations for 2020 (based on the most current information and assumptions). EPCOR Southern Bruce requires services from Treasury Operations in order to provide natural gas service to its customers such as i) cash forecasting and management including ensuring short-term working capital requirements are met and that there is an availability of cash on a day-to-day basis and ii) the accounting of all treasury and loan transactions.

4.Staff.16

Reference: Exhibit 4 / Tab 1 / Schedule 1 / Pgs.60-61

Preamble: *EPCOR Southern Bruce has used Enbridge Gas' depreciation rates for the Union Gas rate zone as per the CIP process. EPCOR Southern Bruce has not undertaken a depreciation study in this application but intends to complete one for the next rebasing.*

Questions:

EPCOR Southern Bruce has used a depreciation rate of 3.82% for meters in line with that used by the Union Gas rate zone. For the Aylmer franchise area cost of service application (EB-2018-0336), EPCOR used a depreciation rate of approximately 10% for meters. Does EPCOR Southern Bruce intend to use an actual rate of 10% upon rebasing or continue using 3.82%?

Responses:

In EPCOR's next rebasing application (year 11) it would expect to base any proposed changes in depreciation rates on the experience of that utility.

4.Staff.17

Reference: Exhibit 4 / Tab 1 / Schedule 3 / Pgs.1

Preamble: *In the table, Projected Continuity Schedule of Contribution in Aid of Construction (CIAC) to Enbridge- Stations, the Additions continue to increase year over year. EPCOR Southern Bruce, throughout the application, has only indicated a CIAC for one year in the amount of $2.935M in 2019 related to the Enbridge customer station.*

Questions:

Please explain the increase in additions post 2019 and explain the Continuity Schedule.

Responses:

EPCOR has determined that the links building this table contained an inadvertence reference error. The corrected table is below. The error was presentational and has no impact on rate base or revenue requirement.

Table OEB 1.Staff.17

Projected Continuity Schedule of CIAC to Enbridge - Station

(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1											
Row 2	**Gross Fixed Assets**										
Row 3	Opening Balance	0	2,935	2,935	2,935	2,935	2,935	2,935	2,935	2,935	2,935
Row 4	Additions	2,935	0	0	0	0	0	0	0	0	0
Row 5	Retirement	0	0	0	0	0	0	0	0	0	0
Row 6	Closing Balance	2,935	2,935	2,935	2,935	2,935	2,935	2,935	2,935	2,935	2,935
Row 7											
Row 8	Accumulated Depreciation										
Row 9	Opening Balance	0	-39	-116	-193	-270	-348	-425	-502	-579	-656
Row 10	Depreciation	-39	-77	-77	-77	-77	-77	-77	-77	-77	-77
Row 11	Retirement	0	0	0	0	0	0	0	0	0	0
Row 12	Closing Balance	-39	-116	-193	-270	-348	-425	-502	-579	-656	-734

4.Staff.18

Reference: Exhibit 4 / Tab 3 / Schedule 1 / Pgs.8-19

Preamble: *EPCOR Southern Bruce has provided a gas supply plan for the period 2019 to 2022. The plan analyses three supply options or strategies. Each supply option assumes gas supply is delivered from Enbridge Gas' transportation network to EPCOR Southern Bruce's distribution network through the M17 transportation contract, which transports the gas from the Dawn receipt point to the Dornoch interconnection point. EPCOR Southern Bruce has further noted that charges related to transportation, storage and load balancing charges can be high in the first years of service. EPCOR Southern Bruce intends to pass on to customers, costs for unutilized transportation or storage capacity.*

Questions:

(a) Can EPCOR Southern Bruce enter into a contract with Enbridge Gas for lower transportation capacity in the initial years to match demand and increase it later when more customers are connected to the distribution system?

(b) It is expected that Enbridge Gas will have to reinforce the Owen Sound transmission line to serve the South Bruce area. When is the demand from EPCOR Southern Bruce expected to reach the threshold at which point reinforcement will be required?

(c) Will the Enbridge Gas transportation charges be different before and after the reinforcement of the Owen Sound transmission line?

Responses:

(a) EPCOR understands that it could enter into an M17 agreement for a lower transportation contract demand in the early years that would provide for increases at specified times. However, given the M17 as proposed by Enbridge, EPCOR does not believe that this would be in the best interests of its customers.

Although EPCOR requested Enbridge's M9 service, Enbridge has advised it was unavailable and has proposed a new M17 service to meet EPCOR's requirements in Southern Bruce. The M17 service is a fully unbundled transportation-only service unlike the M9 service that EPCOR contracts from Enbridge to service the Aylmer area. The terms and conditions of the proposed service (EB-2018-0244) have not been approved by the OEB. Enbridge is proposing to apply the EBO 188 economic test that would require EPCOR to pay a contribution amount (CIAC) representing the difference between the capital and incremental O&M costs to provide the service and the net present value of the revenue stream over the contract period. Within such a framework there is no net financial benefit to EPCOR's customers as lowering the Contract Demand volume in the early years would result in a corresponding increase to the CIAC amount. Moreover, contracting for a higher amount in the early years, provides capacity should customers attach to the system at a rate higher than projected. If the contract was for a lower capacity, and did not provide for specified increases in contract demand in the formative years, the risk that capacity may be unavailable when required would increase.

EPCOR anticipates commencing service in late 2019. Enbridge has advised EPCOR that it does not have sufficient capacity to provide EPCOR's anticipated contract demand without expanding its Owen Sound Line. In order to commence service in 2019, Enbridge has agreed to make some initial capacity available on the basis that it will be completing its Owen Sound Line reinforcement project in 2020.

(b) See response to (a) above.

(c) In addition to paying a CIAC for the net incremental cost to provide the capacity to meet EPCOR's contract demand, EPCOR also understands that Enbridge Gas's proposed M17 transportation charges will increase over time both to help pay for the balance of the reinforcement costs of the Owen Sound transmission line to meet Enbridge's other growth requirements served by that project, as well as other transmission line reinforcement project costs to meet Enbridge's growth requirements met through the expansion of "Other Transmission" line (excluding the Dawn-parkway system). EPCOR does not agree with the proposed economic test that is being used to determine the CIAC and will address this concern in Enbridge's Owen Sound Line reinforcement project LTC application or EB-2018-0244.

4.Staff.19

Reference: Exhibit 4 / Tab 3 / Schedule 1 / Pgs.28-29

Preamble: *EPCOR Southern Bruce has recommended the annual baseload supply option that will best allow it to manage shifting demand requirements throughout the year and provides operational flexibility through service attributes and contract parameters. In its gas supply plan, EPCOR Southern Bruce has provided the commodity delivery point as Dawn.*

Questions:

Please provide additional information on how EPCOR Southern Bruce plans to purchase the commodity. Will the entire required volumes be purchased from Dawn through third party marketers or is EPCOR Southern Bruce going to purchase the commodity at different locations and transport the gas to Dawn?

Responses:

EPCOR's proposed gas supply plan assumes the utility has entered into a contract based on Enbridge's proposed M17 rate. The draft M17 contract is a point to point transportation service from Dawn / Kirkwall / Parkway to Dornoch. Under the M17 tariff, EPCOR is required to provide gas supply for system customers. The current plan is to purchase delivered gas through third party marketers as prescribed by the M17 tariff.

For greater clarity, EPCOR does not plan to contract for transportation capacity upstream of Dawn / Kirkwall / Parkway, however, EPCOR has issued an RFP for a third party gas supply manager to provide recommendations to ensure cost effectiveness and reliability consistent with the OEB's Framework for the Assessment of Distributor Gas Supply Plans. The Gas Supply Manager will identify any capacity constraints as part of the services.

Should EPCOR be eligible for an M9 rate, gas supply is provided by Enbridge at OEB approved Weighted Average Cost of Gas or WACOG.

6.Staff.20

Reference: Exhibit 6 / Tab 1 / Schedule 1 / Pgs.3-8
Exhibit 1 / Tab 2 / Schedule 1 / Pgs.16-17

Preamble: *EPCOR Southern Bruce has indicated that a delay in the OEB approval process has impacted the construction schedule and triggered a revenue deficiency of $1.764 million on a net present value basis compared to that included in the CIP. This includes $1.640 million in distribution revenue and $0.124 million in upstream charges.*

Questions:

(a) EPCOR was awarded $22.0 million under the Natural Gas Grant Program (NGGP) for development of the Southern Bruce natural gas distribution system. On September 26, 2018, EPCOR was informed that the Province will not be executing any transfer payments under the NGGP and therefore EPCOR would not receive any funding for the project. On December 21, 2018, EPCOR received confirmation that the Southern Bruce expansion project was eligible for rate protection and would receive the $22 million funding. Please confirm that the cancellation of the NGGP also impacted the construction schedule as the project was not economically feasible without external funding.

(b) EPCOR Southern Bruce is seeking recovery of $124,000 in upstream charges. Has EPCOR Southern Bruce entered into a rate contract with Enbridge Gas? If no, why does EPCOR Southern Bruce not have the ability to push the timeline of the rate agreement such that upstream charges are not triggered when no customers are expected to be connected to the system?

Responses:

(a) EPCOR confirms that the cancellation of the NGGP impacted the construction schedule as the project is not economically feasible without external funding and as a result the leave to construct application (EB-2018-0263) for the project was placed in abeyance. EPCOR notes that the Provincial Government is committed to expanding natural gas access across Ontario and introduced Ontario Regulation 24/19 which includes Schedule 1 that identifies the Southern Bruce Project as eligible for $22.0 million. This Regulation was filed on March 8, 2019.

(b) EPCOR has not entered into a contract for transportation services with Enbridge Gas. At this time, EPCOR is intending to enter into agreements that will result in upstream charges starting approximately November 1, 2019, or as soon thereafter as both EPCOR and Enbridge are able to commence service. EPCOR expects to have several customers connected to the system in December 2019. At the time this application was filed, EPCOR had been informed by Enbridge that it would be required to contract for its 10-year forecast capacity in 2019. This timeline was used to calculate the $124,000 in upstream charges it is seeking to recover. Enbridge has subsequently informed EPCOR that it will allow EPCOR to contract for a lesser capacity in 2019 and the remaining capacity in 2020 when the Owen Sound Reinforcement is complete. The change in timeline will impact the $124,000 value. That impact is unknown at this time. As detailed in OEB 3.Staff.10, EPCOR is proposing to finalize upstream charges once Enbridge's tariff and leave to construct applications are approved by the OEB.

7.Staff.21

Reference: Exhibit 7 / Tab 1 / Schedule 1 /Pg.3

Preamble: *EPCOR Southern Bruce has provided results of a cost allocation study to determine the allocation of costs amongst the different rate classes and the resulting revenue to cost ratios. In completing this study, EPCOR Southern Bruce has used its current best view of what the Southern Bruce system will look like in 2028. The current study is based on its CIP, the EPCOR Aylmer natural gas distribution system and management judgement.*

Questions:

(a) Did EPCOR Southern Bruce adopt the Aylmer cost allocation model as is or did it make certain adjustments to the model to incorporate the distinct elements of the Southern Bruce system? If any adjustments were made, please describe those adjustments.

(b) Will EPCOR Southern Bruce complete a full cost allocation study to support its next rebasing application?

Responses:

a) EPCOR has applied the same cost allocation principles, three-step methodology (functionalization, classification and allocation), and cost allocation model framework for both the EPCOR Southern Bruce and Aylmer operations. EPCOR has adjusted the cost allocation model to reflect the distinct elements of the Southern Bruce system as described below:

- Gas Supply – the cost allocation model has been expanded to include each cost element of the proposed gas supply plan for Southern Bruce (commodity, storage, load balancing, and upstream transportation).
- Distribution System Configuration – the proportion of high-pressure and low-pressure distribution mains and how each rate class uses the distribution system has been incorporated into the cost allocation model for Southern Bruce.
- Southern Bruce Cost Structure – adjustments have been made to reflect the unique cost structure of the Southern Bruce system. This includes the Enbridge Contribution in Aid of Construction (CIAC), the $22.0 million grant as a result of Ontario Regulation 24/19, costs directly assigned to industrial customers, and deferred revenues.

  Rate Classes – the costs are allocated to the four rate classes proposed for Southern Bruce, based on the year 10 forecast of customer connections, sales volumes, demand and customer services for the Southern Bruce operation.

b) EPCOR will complete a full cost allocation study to support the next rebasing application for Southern Bruce.

7.Staff.22

Reference: Exhibit 7 / Tab 1 / Schedule 1 / Pg.15

Preamble: The results of the cost allocation analysis indicate that EPCOR Southern Bruce's revenue to cost ratios are within a range of plus or minus 25% while the distribution revenue to cost ratios range from 1.01 to 1.37.

Questions:

(a) Please explain why a distribution revenue to cost ratio of 1.35 and 1.37 for Rate Classes 11 and 16 respectively, and a revenue to cost ratio of 0.78 for Rate 6 is a reasonable outcome.

(b) Please provide the resulting revenue to cost ratios and the annual billing amounts for a typical customer if the distribution revenue to cost ratio for Rate 6 is increased to 0.90 and the benefit of the resulting revenue is distributed between Rates 11 and 16.

Responses:

a) EPCOR notes that economic regulators typically provide a range of acceptable revenue-to-cost ratio range (which can vary by regulator) to recognize both the inherent imprecision of the cost allocation process and the need to pursue (from time-to-time) other rate design objectives. The outcome that EPCOR is targeting with its proposed rates for Southern Bruce is to attract customers in all rate classes in sufficient numbers to ensure the long term economic viability of the utility. The proposed rates, which would be in effect during the 10-year rate stability period, represent a necessary trade-off between typical cost of service and a market based approach to rate design.

When designing rates for a mature utility with existing customers, a focus on cost of service principles is justified. This includes revenue to cost ratios that identifies cross subsidization among existing customers in each rate category and ensures that a utility's customer base is not cross subsidizing system expansion targeted at bringing new customers onto the system. Under such a scenario EPCOR understands that a revenue to cost ratio of between 0.80 and 1.20 is generally considered acceptable, with a value closer to 1.0 being more desirable.

In the case of a greenfield system expansion such as Southern Bruce, there are no existing customers that would be negatively impacted by the proposed rates. Rather the intent of EPCOR's proposed rates is to attract sufficient new customers onto the system such that the utility's economic viability is assured. Each potential customer, no matter which rate class they may qualify for, will make an economic decision whether to connect to the system or remain with their existing energy provider. If a potential customer does not find the proposed rates economically compelling they are under no obligation to connect, but can remain with their existing energy provider. Once a customer makes the choice to connect to the system their rates will be protected during the 10-year rate stability period, after which EPCOR will be filing a rates application based on typical cost of service principles.

As detailed in Exhibit 7.1, while participating in the OEB's competitive process, EPCOR's market research suggested that in order for customers to connect to the distribution system in sufficient numbers to make the utility viable they required a savings of at least 20%. EPCOR used the resulting customer connection forecast to determine its revenue requirement, which was agreed to by the OEB in determining that EPCOR was the successful proponent. As noted by the OEB, "Proponents were expected to include details on their forecast attachments as part of the proposals, with the successful proponent to be held to its forecast for rate-making purposes."[1] EPCOR accepts this risk of attracting customers to connect, however, this connection forecast is based on being able to offer rates that all classes of customers find compelling. Reliance on a rate design that focuses specifically on cost of service principles will impact the rates EPCOR is proposing and could therefore materially influence customer savings and connection rates, thereby impacting the economic viability of the utility.

The intent of the cost allocation study included in the application is to provide a cost of service perspective as well as a comparison and reasonableness check of the proposed rates and revenue to be recovered from each rate class. However, as discussed above, relying solely on this study to determine rates could negatively impact the economic viability of the utility. Given the above, EPCOR is of the view that the revenue to cost ratios that are derived from the proposed rates are within reason and will result in customer connections during the 10-year rate stability period that are sufficient to ensure the economic viability of the utility.

[1] EB-2016-0137/0138/0139, Decision and Order Southern Bruce Expansion Applications, April 12, 2018, Section 4.1, Customer Attachments page 8

b)

	Description	Col. 1 Total	Col. 2 Rate 1 - General Firm Service	Col. 3 Rate 6 - Large Volume General Firm Service	Col. 4 Rate 11 - Large Volume Seasonal Service	Col. 5 Rate 16 - Contracted Firm Service
Row 1	Revenue	7,846.23	5,298.99	1,195.32	215.38	1,136.54
Row 2	Cost of Service	7,683.94	5,243.44	1,328.00	179.78	932.72
Row 3	Over / Under Contributions	162.29	55.55	-132.68	35.60	203.82
Row 4	Revenue to Cost Ratio	1.02	1.01	0.90	1.20	1.22

2020
Rate 1 - General Firm Service
Existing Residential
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	25.32	304
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 100 m3	1,001	27.1351	272
Row 7			Next 400 m3	1,148	26.6006	305
Row 8			Over 500 m3	0	25.8148	0
Row 9	**Total Distribution Charge**			**2,149**		**881**
Row 10	Fixed Charge Ratio of Distribution Charge					34.49%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		2,149	1.4779	32
Row 13		Transportation and Storage Charge		2,149	2.7398	59
Row 14	Gas Supply Charge			2,149	12.6433	272
Row 15	**Total Non-Distribution Charges**					**362**
Row 16						
Row 17	**Total Revenue**					**1,243**

2020
Rate 1 - General Firm Service
New Residential
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	25.32	304
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 100 m3	993	27.1351	269
Row 7			Next 400 m3	1,073	26.6006	285
Row 8			Over 500 m3	0	25.8148	0
Row 9	**Total Distribution Charge**			**2,066**		**859**
Row 10	Fixed Charge Ratio of Distribution Charge					35.38%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		2,066	1.4779	31
Row 13		Transportation and Storage Charge		2,066	2.7398	57
Row 14	Gas Supply Charge			2,066	12.6433	261
Row 15	**Total Non-Distribution Charges**					**348**
Row 16						
Row 17	**Total Revenue**					**1,207**

2020
Rate 1 - General Firm Service
Small Commercial
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	25.32	304
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 100 m3	1,198	27.1351	325
Row 7			Next 400 m3	2,475	26.6006	658
Row 8			Over 500 m3	1,020	25.8148	263
Row 9	**Total Distribution Charge**			**4,693**		**1,551**
Row 10	Fixed Charge Ratio of Distribution Charge					19.59%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		4,693	1.4779	69
Row 13		Transportation and Storage Charge		4,693	2.7398	129
Row 14	Gas Supply Charge			4,693	12.6433	593
Row 15	**Total Non-Distribution Charges**					**791**
Row 16						
Row 17	**Total Revenue**					**2,342**

2020
Rate 1 - General Firm Service
Small Agricultural
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	25.32	304
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 100 m3	1,199	27.1351	325
Row 7			Next 400 m3	2,484	26.6006	661
Row 8			Over 500 m3	1,037	25.8148	268
Row 9	**Total Distribution Charge**			**4,720**		**1,558**
Row 10	Fixed Charge Ratio of Distribution Charge					19.50%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		4,720	1.4779	70
Row 13		Transportation and Storage Charge		4,720	2.7398	129
Row 14	Gas Supply Charge			4,720	12.6433	597
Row 15	**Total Non-Distribution Charges**					**796**
Row 16						
Row 17	**Total Revenue**					**2,353**

2020
Rate 6 - Large Volume General Firm Service
Medium Commercial
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	103.30	1,240
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 1000 m3	9,832	29.2051	2,871
Row 7			Next 6000 m3	17,101	26.7018	4,566
Row 8			Over 7000 m3	0	25.5754	0
Row 9	**Total Distribution Charge**			**26,933**		**8,677**
Row 10	Fixed Charge Ratio of Distribution Charge					14.28%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		26,933	2.9279	789
Row 13		Transportation and Storage Charge		26,933	5.7283	1,543
Row 14	Gas Supply Charge			26,933	12.6433	3,405
Row 15	**Total Non-Distribution Charges**					**5,737**
Row 16						
Row 17	**Total Revenue**					**14,414**

2020
Rate 6 - Large Volume General Firm Service
Large Commercial
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Bill Amount
Row 3	Monthly Fixed Charge		12	1	103.30	1,240
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		First 1000 m3	11,715	29.2051	3,421
Row 7			Next 6000 m3	40,793	26.7018	10,892
Row 8			Over 7000 m3	23,177	25.5754	5,928
Row 9	**Total Distribution Charge**			**75,685**		**21,481**
Row 10	Fixed Charge Ratio of Distribution Charge					5.77%
Row 11				Volumes (m3)	Charge (¢/m3)	
Row 12	Upstream Charges	Upstream Recovery Charge		75,685	2.9279	2,216
Row 13		Transportation and Storage Charge		75,685	5.7283	4,335
Row 14	Gas Supply Charge			75,685	12.6433	9,569
Row 15	**Total Non-Distribution Charges**					**16,120**

2020
Rate 11 - Large Volume Seasonal Service
Sample Dryer 1
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Revenue
Row 3	Monthly Fixed Charge		8	1	206.59	1,653
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		Over 0 m3	101,499	13.7757	13,982
Row 7	**Total Distribution Charge**			**101,499**		**15,635**
Row 8	Fixed Charge Ratio of Distribution Charge					10.57%
Row 9				Volumes (m3)	Charge (¢/m3)	
Row 10	Upstream Charges	Upstream Recovery Charge		101,499	0.0353	36
Row 11		Transportation and Storage Charge		101,499	1.8446	1,872
Row 12	Gas Supply Charge			101,499	12.6433	12,833
Row 13	**Total Non-Distribution Charges**					**14,741**
Row 14						
Row 15	**Total Revenue**					**30,376**

2020
Rate 11 - Large Volume Seasonal Service
Sample Dryer 2
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Revenue
Row 3	Monthly Fixed Charge		8	1	206.59	1,653
Row 4						
Row 5			Rate Block (m3)	Volumes (m3)	Charge (¢/m3)	
Row 6	Delivery Charge		Over 0 m3	338,332	13.7757	46,608
Row 7	**Total Distribution Charge**			**338,332**		**48,260**
Row 8	Fixed Charge Ratio of Distribution Charge					3.42%
Row 9				Volumes (m3)	Charge (¢/m3)	
Row 10	Upstream Charges	Upstream Recovery Charge		338,332	0.0353	119
Row 11		Transportation and Storage Charge		338,332	1.8446	6,241
Row 12	Gas Supply Charge			338,332	12.6433	42,776
Row 13	**Total Non-Distribution Charges**					**49,136**
Row 14						
Row 15	**Total Revenue**					**97,397**

2020
Rate 16 - Contracted Firm Service
(Dollars unless Otherwise Specified)

	Description		Col. 1	Col. 2	Col. 3	Col. 4
Row 1						
Row 2			Months	Effective Cx (Cx)	Charge ($/Cx/month)	Revenue
Row 3	Monthly Fixed Charge		12	1	1,519.05	18,229
Row 4						
Row 5				Contracted Demand (m3/day)	Charge (¢/m3/month)	
Row 6	Delivery Charge			50,000	92.0445	552,267
Row 7	**Total Distribution Charge**					**570,496**
Row 8	Fixed Charge Ratio of Distribution Charge					3.20%
Row 9				Contracted Demand (m3/day)	Charge (¢/m3/month)	
Row 10	Upstream Charges	Upstream Recovery Charge		50,000	14.2815	85,689
Row 11		Transportation Charge - Contracted Demand		50,000	18.9954	113,972
Row 12						
Row 13	**Total Non-Distribution Charges**					**199,661**
Row 14						
Row 15	**Total Revenue**					**770,157**

8.Staff.23

Reference: Exhibit 8 / Tab 1 / Schedule 1 / Pg.3

Preamble: *EPCOR Southern Bruce has proposed four rate classes. Rate 6 is designed to apply to medium and large commercial, and agricultural market segments with year-round gas requirements. Customers whose requirements are greater than 10,000 m3 per annum are eligible for service under this rate class.*

Questions:

(a) Please clarify whether there is an upper limit for Rate 6 with respect to the annual consumption at which point the customer would move to another rate class or would need to become a contract customer.

Responses:

(a) There is no upper limit for Rate 6 with respect to the annual consumption at which point the customer would move to another rate class or would need to become a contract customer.

8.Staff.24

Reference: Exhibit 8 / Tab 1 / Schedule 1 / Pgs.8-9

Preamble: *Rate 11 and Rate 16 customers have limits on the volume of gas they can draw from the system. Any volumes used by a Rate 11 customer during the off-season period will be deemed overrun gas. For Rate 16 customers, overrun gas constitutes usage beyond the peak hour or daily limits defined in the contract with the specified customer. EPCOR Southern Bruce has proposed to permit authorized overrun at its discretion. Should customers fail to obtain authorization from EPCOR Southern Bruce prior to using overrun gas, they will incur unauthorized overrun charges plus applicable penalties.*

Questions:

(a) Since there are only seven customers in rate classes 11 and 16, has EPCOR Southern Bruce informed them about overrun charges and the associated penalties for unauthorized overrun?

Responses:

(a) EPCOR discussed the overrun charges and the associated penalties for unauthorized overrun with the two class 16 customers as included in the CIP. These discussions included providing them with a draft of the proposed tariff.

EPCOR has discussed the seasonal nature of the service with potential Rate 11 customers, confirmed that EPCOR would offer firm service during the on-season period and that customers would have to contact EPCOR if they wanted to access natural gas outside of the proposed season.

Inclusion of penalties for unauthorized overrun aligns with a principle in offering this type of service that overrun is not intended as a substitute for contracting for a service to meet the customer's expected requirements. Arranging for the appropriate level of service will help ensure the safety and reliability of the system of all customers.

8.Staff.25

Reference: Exhibit 8 / Tab 1 / Schedule 1 / Pg.14

Preamble: *EPCOR Southern Bruce has proposed Conditions of Service that are in line with those applied for in the EPCOR Aylmer distribution rates application (EB-2018-0336). Similarly, the proposed service charges and miscellaneous charges are the same as those provided in the Aylmer distribution rates application*.

Questions:

Please confirm if the Conditions of Service and proposed service charges and miscellaneous charges are in line with those agreed to in the Aylmer distribution rates application settlement proposal dated June 3, 2019. If there are any differences, does EPCOR Southern Bruce intend to adopt them?

Responses:

EPCOR Southern Bruce's proposed service charges and miscellaneous charges are largely aligned with those agreed to in the settlement proposal filed for the Aylmer distribution rate application EB-2018-0336. EPCOR Southern Bruce will revise its proposed Returned Cheque/Payment Charge to remove the Disconnection Charge to align with what was agreed to for Aylmer. With these adjustments, the only remaining differences are:

- Connection Charge - EPCOR Southern Bruce does not charge the Connection Charge for the initial connection, and
- Installation of Service Lateral Charge - EPCOR Southern Bruce does not charge for the first 30 meters of pipe.

EPCOR does not intend to adopt Aylmer's charges for the above two items. Southern Bruce's proposed charges of $0 for these items have been set at this level to assist in incenting customers to convert to natural gas and facilitate the greenfield utility's customer conversion strategy. The table below provides a comparison of the proposed service and miscellaneous charges for EPCOR Southern Bruce's with Aylmer's:

Service	A Current Fee (2011)	B Proposed Fee (EB-2018-0336)	C Settled Fee (EB-2018-0336)	D Proposed Fee (EB-2018-0264)	D Revised Proposed Fee (EB-2018-0264)
	EPCOR Aylmer			EPCOR Southern Bruce	
1 Service Work					
2 During normal working hours					
3 Minimum charge (up to 60 minutes)	$90.00	$100.00	$100.00	$100.00	$100.00
4 Each additional hour (or part thereof)	$90.00	$100.00	$100.00	$100.00	$100.00
5 Outside normal working hours					
6 Minimum charge (up to 60 minutes)	$115.00	$130.00	$130.00	$130.00	$130.00
7 Each additional hour (or part thereof)	$95.00	$105.00	$105.00	$105.00	$105.00
8 Miscellaneous Charges					
9 Returned Cheque / Payment	$20.00	$48.00	$20.00	$48.00	$20.00
10 Replies to request for account information	$20.00	$25.00	$25.00	$25.00	$25.00
11 Bill Reprint / Statement Print Requests		$20.00	$20.00	$20.00	$20.00
12 Consumption Summary Requests		$20.00	$20.00	$20.00	$20.00
13 Customer Transfer / Connection Charge	$30.00	$35.00	$35.00	$35.00[1]	$35.00[2]
14 Reconnection Charge	$78.00	$85.00	$85.00	$85.00	$85.00
15 Disconnection Charge	$78.00	$85.00	$0.00	$85.00	$0.00
16 Inactive Account Charge		ENGLP cost to install service	ENGLP cost to install service	ENGLP cost to install service	ENGLP cost to install service
17 Late Payment Charge	1.5% /month, 19.56% /year (effective rate of 0.04896% compounded daily)			1.5% /month, 19.56% /year (effective rate of 0.04896% compounded daily)	1.5% /month, 19.56% /year (effective rate of 0.04896% compounded daily)
18 Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs			Charge based on actual costs	Charge based on actual costs
19 Installation of Service Lateral	$100 first 20 meters. $10/meter thereafter	$100 (minimum). Additional if pipe length exceeds length used to set fee.	$100 first 20 meters. Additional if pipe length exceeds length used to set fee.	No charge for the first 30 meters. Cost if pipe length exceeds 30 meters.	No charge for the first 30 meters. Cost if pipe length exceeds 30 meters.

[2] No Charge for initial connection

EPCOR's Southern Bruce proposed Conditions of Service were drafted in the same manner as Aylmer's Conditions of Service as filed in the original rates application EB-2018-0336. Other than the items related to the specific service and miscellaneous charges noted above EPCOR intends to align its Conditions of Service for Southern Bruce with those agreed to in the settlement proposal filed for the Aylmer distribution rate application EB-2018-0336. Accordingly, EPCOR Southern Bruce will remove from the Conditions of Service all references to a disconnection charge and all miscellaneous and service charges and develop a rate schedule for the miscellaneous and service charges.

The Schedule of Miscellaneous and Service Charges that EPCOR proposes to add to its rate schedules is provided in 8.Staff.25 Attachment 1 and the revised Conditions of Service are provided in 8.Staff.25 Attachment 2.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Schedule of Miscellaneous and Service Charges

	A Service	B Fee
1	Service Work	
2	During normal working hours	
3	Minimum charge (up to 60 minutes)	$100.00
4	Each additional hour (or part thereof)	$100.00
5	Outside normal working hours	
6	Minimum charge (up to 60 minutes)	$130.00
7	Each additional hour (or part thereof)	$105.00
8		
9	Miscellaneous Charges	
10	Returned Cheque / Payment	$20.00
11	Replies to a request for account information	$25.00
12	Bill Reprint / Statement Print Requests	$20.00
13	Consumption Summary Requests	$20.00
14	Customer Transfer / Connection Charge	$35.00[1]
15		
16	Reconnection Charge	$85.00
17		
18	Inactive Account Charge	ENGLP's cost to install service
19		
20	Late Payment Charge	1.5% / month, 19.56% / year (effective rate of 0.04896% compounded daily)
21		
22	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs
23		
24	Installation of Service Lateral	No charge for the first 30 meters.

Note: Applicable taxes will be added to the above charges

Effective: January 1, 2019
Implementation: All bills rendered on or after January 1, 2019
EB-2018-0264

[1] No Charge for initial connection

EPCOR Natural Gas Limited Partnership - Southern Bruce Natural Gas Operations

Conditions of Service

Effective January 1, 2019
EB-2018-0264

TABLE OF CONTENTS

1 PREAMBLE

EPCOR Natural Gas Limited Partnership's Southern Bruce Operations ("EPCOR") commenced development of its natural gas distribution system in 2019 in order to sell and distribute natural gas to Customers within its franchise areas in the Municipality of Arran-Elderslie, Municipality of Kincardine, and the Township of Huron-Kinloss.

These Conditions of Service provide a summary of EPCOR's standards and practices governing the relationship between EPCOR and its Customers. This document does not supersede any terms and conditions set out in EPCOR's Rate Schedules approved by the Ontario Energy Board ("OEB"). EPCOR reserves the right to modify these Conditions of Service at any time.

Capitalized terms are defined in Appendix A.

2 GAS DISTRIBUTION SERVICES

Gas distribution services will be made available to new residential, commercial and industrial Customers within EPCOR's franchise areas if EPCOR, at its sole discretion, determines that:

a) sufficient gas supply exists;
b) sufficient transportation and distribution capacity exists;
c) installation of the infrastructure required would not pose any safety or other risk; and,
d) installation of the infrastructure required is determined to be economically feasible.

2.1 Gas Distribution and/or Supply Interruptions

EPCOR may require Customers to curtail or discontinue the use of gas if the supply of gas is jeopardized in the event of:

a) an actual or threatened shortage of gas due to circumstances beyond EPCOR's control;
b) a curtailment or restricted gas usage being ordered by a governmental authority or agency having jurisdiction; or
c) an event of Force Majeure.

EPCOR may also be required to interrupt gas service from time to time for repair and/or maintenance of its facilities. Except in the case of an emergency, affected Customers will be given reasonable notice of such interruption. EPCOR shall not be liable for any loss of production, nor for any loss or damages whatsoever associated with curtailment, discontinuance, interruption or any other failure of supply.

2.2 Delivery Point

The point of delivery of all gas (or redelivery in the case of gas directly purchased by a Customer) shall be at the outlet of EPCOR's Meter. At the point of delivery, all gas delivered becomes property of the Customer. All gas passing through the Meter, whether it is used or lost through leakage downstream of the Meter, is the Customer's responsibility and the Customer shall pay for that gas.

3 RATE SCHEDULES

The rates EPCOR charges for its various gas distribution and supply services are set out in EPCOR's Rate Schedules, which are approved by the OEB from time to time. When EPCOR's Rate Schedules are amended by the OEB, the amended rate(s) and/or term(s) will apply to Customers on the effective date established by the OEB.

4 INITIATION OF SERVICE

4.1 Application for Service

A potential Customer requesting natural gas service must complete EPCOR's "Application for Natural Gas Service" form ("Application") attached at Schedule 2 to these Conditions of Service. Contract Rate Customers are required to execute a contract for a specified term of not less than one (1) year.

EPCOR may approve an Application, taking into account the criteria set out in Section 2, and the conditions set out in Sections 4.2 and 4.3. If serving the potential Customer would require EPCOR to construct a new Service Lateral, the Customer must also complete EPCOR's "Meter Size and Location Request" form.

A transfer/connection fee, plus applicable taxes will be charged for an approved Application, which will be applied to the Customer's first natural gas bill. In addition, a new Customer may be required to provide a security deposit in accordance with EPCOR's security deposit policy set out in Section 6.3.

The Application for Natural Gas Service form is attached to these Conditions of Service in Schedule 2. This form is also available on EPCOR's website at www.epcor.com under "Sign up details", in person at EPCOR's office or by contacting an EPCOR customer service representative at 1-519-773-5321.

4.2 Main Extensions

EPCOR will make extensions of its natural gas Mains within its franchise area to serve new Customers when EPCOR, at its sole discretion, determines that: (a) the criteria outlined in Section 2 have been met; and (b) the Main Extension will not disturb or impair the service to other Customers. The following criteria will be used by EPCOR to review the economic feasibility of a Main Extension:

a) the full cost of extending the gas Main;
b) the number of potential new Customers that will be served off the Main Extension within the next five (5) years; and
c) the amount of natural gas expected to be used by those Customers.

If the Main Extension is not economically feasible, the potential new Customer(s) will be required to pay a Contribution-in-Aid-of-Construction ("CIAC") in an amount to be determined by EPCOR, consistent with OEB guidelines, to make the Main Extension project economically feasible. If a CIAC is required, EPCOR will notify the potential new Customer(s) of the amount of the CIAC. In addition, the potential new Customer(s) may be required to sign a CIAC agreement. EPCOR will begin planning the installation once the CIAC has been paid in full.

Many factors affect the installation of Main Extensions. As a result, EPCOR cannot guarantee the time required to complete a Main Extension.

4.3 Service Lateral Installations

In addition to the criteria in Section 2 above, the following conditions must be met prior to the installation of Service Laterals within EPCOR's franchise area:

a) an Application and/or contract as outlined in Section 4.1 above have been properly completed and approved/executed;
b) any applicable security deposit has been provided;
c) any associated Main Extensions have been determined to be economically feasible, or the required CIAC has been paid as outlined in Section 4.2; and,
d) all fees for the Service Lateral installation (as described below) have been paid.

For each Service Lateral request, EPCOR shall complete a construction estimate for the Service Lateral extending from the Customer's property line to the Meter location selected by EPCOR as set out in Section 4.4. The cost of installing the first 30 meters of a natural gas Service Lateral will be borne by EPCOR. If the length of pipe required to bring the Service Lateral to the Meter location exceeds this length, the Customer will be charged for the installation of pipe in excess of 30 meters.

EPCOR may, at its sole discretion, accommodate requests made by the Customer regarding the location of the service or other specific requirements and in such cases, the Customer will be responsible for any additional costs associated with the request.

EPCOR will try to restore Customers' property to the approximate condition in which it was found prior to EPCOR's work. This includes property that is excavated or disrupted during laying, constructing, repairing or removing EPCOR's facilities. Such restoration costs are included in the installation fees charged to the Customer.

Many factors affect the installation of services. As a result, EPCOR cannot guarantee the time required to install a new service.

A Meter connection shall be established as soon as practical after the installation of the service line at the Customer's premises and will be subject to EPCOR's monthly fixed charge from that date. If a Customer does not have any natural gas consumption within 12 months of installation of a new gas service, they will be required to reimburse EPCOR for any service line installation costs not covered by any Service Lateral installation fee charged at the time of installation.

4.4 Meter Locations

EPCOR will determine the location of any Customer Meter. EPCOR will make every effort to install Meters to be accessible for inspection, reading, testing, maintenance and exchange. All Meter locations must comply with all applicable legal requirements, including the *Technical Standards and Safety Act* and its associated regulations.

For Residential Customers, Meters may be located on the front or on either side of the dwelling receiving gas service. A Meter located on the side of a dwelling cannot be greater than ten feet from the front corner of the dwelling. When the distance from the property line to a dwelling or building requiring the natural gas service exceeds 100 meters, the Meter may be required to be located near the property line and the Customer will be responsible for the installation of the piping from the outlet of the Meter as per Section 4.6.

Where outside Meters are installed in locations that do not afford reasonable protection from damage, a physical barrier will be provided as part of the installation. Customers are subsequently responsible for the protection of all metering equipment necessary for the supply of gas, and for keeping it accessible at all times. If at the time of installation, a Meter is adequately protected, and the protection is subsequently compromised by alterations to the property, the Customer will be responsible for EPCOR's cost to install meter protection. Customers will be held liable for any or damage to EPCOR's metering or regulating equipment on their premises that is determined, in EPCOR's judgment, to be beyond ordinary wear and tear, and shall pay EPCOR the cost of any necessary repairs or replacements.

4.5 Alterations or Service Relocations

The cost of work done to alter or relocate existing services and equipment solely for the convenience of the Customer, or to accommodate a Customer's modified requirements, will be charged to the Customer.

4.6 Customer Piping, Appliances and Equipment

Customers shall, at their own expense, equip their premises with all piping, controls, safety devices and other attachments from the outlet of the Meter to the appliances or equipment served. Customers are responsible for maintaining the piping and equipment beyond the outlet (customer) side of the Meter, at their own expense. Customers shall ensure that all such piping and attachments are installed and maintained in accordance with EPCOR's requirements contained herein, the *Technical Standards and Safety Act* (and associated regulations), and any other applicable laws, regulations, rules, codes or standards.

Meters will not be connected to a Customer's piping when that piping, and/or appliances or equipment attached thereto, is known by EPCOR to be defective or not in accordance with applicable laws, regulations, rules, standards or codes. EPCOR reserves the right to discontinue service at any time should it find the piping, venting, appliances or other gas equipment on the Customer's premises to be defective, in an unsafe condition or not in compliance with laws, regulations, rules, standards or codes.

The Customer is required to immediately notify EPCOR of any leakage or escape of natural gas on the customer's premises by calling the 24-hour emergency number at 1-519-773-5321.

EPCOR shall not be liable to the Customer for any damages, and the Customer shall indemnify EPCOR from and against all loss, cost, damages, injury, or expense associated with any injury or damage to persons or property arising, either directly or indirectly, from or incidental to the escape of gas or products of combustion of gas from piping, controls, appliances or appliances that are on the outlet side of the Meter.

4.7 Inspections of Installations

All new installations of supply piping, gas appliances and installations on premises served with natural gas for the first time, are required to be inspected prior to gas being introduced to the premises. In addition to inspections in the instance of a new installation, additional inspections may be performed from time-to-time, including when Meters are changed or physically reset and when gas supply is restored to a premises for any reason. Inspections are governed by the *Technical Standards and Safety Act* and associated regulations

If an inspection reveals that repairs or adjustments are required to the Customer's equipment, the Customer will be advised and the required repairs or adjustments must be completed by the Customer prior to the gas being turned on.

5 MAINTENANCE OF SERVICE

5.1 Customer Service

Only EPCOR or its authorized representatives shall be permitted to perform work on EPCOR's Meters, regulators, piping, and equipment. All connections and disconnections of Meters and regulators, and piping connections to, or disconnections from, EPCOR's facilities must be completed by an authorized EPCOR representative.

EPCOR provides regular service during the normal working hours, and emergency service 24 hours a day. EPCOR does not charge for the response and investigation of natural gas leaks, insufficient natural gas supply complaints, and any required inspections. Repairs required to remedy natural gas leaks and insufficient supply of natural gas from causes on the outlet side of the Meter will be charged to the Customer on a time and material basis.

EPCOR will provide regular maintenance required for the proper use of any EPCOR-owned equipment at no charge to the Customer. Customers will also not be charged for service required due to the failure of EPCOR equipment.

5.2 Access to Customer Premises

The Customer shall ensure that EPCOR has access to the Customer's premises at all reasonable times and upon reasonable notice (unless in case of an emergency, as determined by EPCOR in its sole discretion, EPCOR is unable to provide reasonable notice) for the purposes of inspecting, repairing, testing, replacing, altering or disconnecting any Meter, Service Lateral, appliance or equipment used in connection with gas service within or outside the premises.

5.3 Meter Testing

Meters will be tested: (a) at EPCOR's option; (b) at the request of the Customer; or (c) as required by law. Customers disputing the accuracy of their Meter can initiate the test process by filing a complaint with Measurement Canada and requesting a Meter inspection. The Customer contacting Measurement Canada directly maintains the independence of the dispute process.

EPCOR is required to periodically remove and submit Meters for government inspection in accordance with the *Electricity and Gas Inspection Act*. As a result, EPCOR may arrange an appointment to remove the existing Meter and replace it with a new one. To complete this work, the gas supply to the Customer Meter will be shut off temporarily. After the new Meter has been installed and gas supply is reinstated, the Customer's gas appliances will be relit and inspected.

Note that if EPCOR does not receive a response after two or more attempts to contact a Customer regarding the removal of a Meter for inspection, the Customer's Meter will be removed and replaced with a new one and the gas supply left turned off. The Customer will then be required to call EPCOR to arrange an appointment to have the Meter turned on, gas supply restored to the premises and the natural gas appliances relit and inspected.

In the event a Meter is found to register with an error outside of the regulated thresholds, the provisions of the *Electricity and Gas Inspection Act* will be applied to determine the error duration for the purposes of retroactive bill corrections.

There is no charge for this service unless the Meter is tested at the Customer's request and it is determined that the Meter meets regulated accuracy requirements. In such case, EPCOR will charge the Customer all costs associated with the Meter removal/replacement and testing, and any applicable inspection fees.

5.4 Resale Prohibited

Gas taken by the Customer through the Meter shall not be resold or redistributed other than in accordance with all applicable laws and regulations and orders of the OEB or any governmental authority having jurisdiction.

6 CUSTOMER CARE

This Section 6, unless specifically stated otherwise, applies to all Customers, with the exception of Contract Rate Customers. For those customers who have entered into specific contracts with EPCOR, the terms and conditions set out in that contract will supersede the information contained in this section. In this section, the Customer may also be referred to as ”you”.

All Customers must comply with these Conditions of Service and will be obliged to pay for all gas supplied and/or delivered to the Customer’s premises and all items billed to the Customer by EPCOR.

6.1 Setting up an Account

Potential new Customers of EPCOR, and existing Customers moving premises, must notify EPCOR and complete an “Application for Natural Gas Service” form at least three business days prior to their planned move. If advance notice is not given, accounts may be retroactively adjusted up to a maximum of 30 days from the date on which notification of the move was provided to EPCOR.

6.2 Meter Reads

EPCOR reads its Customer Meters every month. You must provide EPCOR or its representative access to your premises and Meter, for Meter reading purposes, during normal working hours. Customers are responsible for the protection of all metering equipment necessary for the supply of gas and for keeping it accessible at all times. This includes refraining from placing vegetation, structures of any kind, whether permanent or temporary, and other objects within 60 centimeters (24 inches) around the Meter.

If EPCOR has been unable to read your Meter during normal working hours, arrangements can be made to obtain a reading at your convenience. You can also submit your own Meter reading by calling an EPCOR customer service representative at 1-519-773-5321. If EPCOR is not able to read the Meter and you do not submit a reading, your bill will be issued based on an estimated reading. Any necessary adjustments due to estimated bills will be made on the next regular billing after EPCOR has obtained a reading.

6.3 Security Deposits

6.3.1 Security Deposit Requirements

EPCOR reserves the right to request a security deposit from its Customers as a condition of supplying gas service. Security deposits are used to secure payment for future charges in the event that a Customer does not pay their bill and are necessary to protect both EPCOR and its Customers from increased rates resulting from non-paying Customers. Security deposits are not to be considered as prepayment for future charges.

All Customers will be required to provide a security deposit unless the requirement is waived by EPCOR. EPCOR will waive the security deposit if you:

a) are a General Service Customer and meet EPCOR’s credit requirements;

b) can provide a letter of reference from any natural gas or electricity utility in Canada confirming good payment history;
c) have moved, and your previous EPCOR account has a good payment history; or
d) have requested the security deposit requirement be waived and are an eligible low-income customer as set out in Section 6.11.

Good payment history must be demonstrated for a time period of at least one (1) year for Residential Customers, five (5) years for General Service Customers and seven (7) years for all other Customers. Good payment history must be demonstrated for the most recent period of time on record for the Customer, some of which must have occurred within the past 24 months.

Good payment history is maintained unless the Customer has experienced any of the following in the above indicated time frame:

a) received a disconnection notice from EPCOR, or another natural gas vendor or electricity distributor;
b) had a payment to EPCOR returned for insufficient funds; or,
c) had at least one visit from EPCOR personnel to their premises for purpose of payment of an account in arrears, to shut off or limit the natural gas supply to the Customer's premises for reasons of non-payment.

The security deposit amount is determined based on the average monthly natural gas consumption over the last 12 consecutive months, within the past two (2) years, at the specific address in which the natural gas service is or will be installed. The maximum amount of the security deposit EPCOR may require from a Customer shall be 2.5 times the average actual monthly consumption over the past 12 consecutive months. Should the Customer have no historical consumption on record, an estimate of consumption will be used.

If you are required to provide a security deposit it will be charged on your next EPCOR bill. Late payment fees will not be applied to the balance owing on your security deposit for a period of up to six (6) months, provided you are making regular monthly installments of at least 1/6th of the balance owing on your security deposit.

When a Customer has been disconnected for non-payment, the security deposit amount will be determined at 2.5 times the Customer’s highest actual or estimated monthly consumption, within the most recent 12 consecutive months in the past two (2) years.

If a Customer moves to another location where natural gas service is provided by EPCOR, the security deposit requirements for the Customer shall be reviewed. Depending on the consumption at the new location and the recent payment history of the Customer, the amount of the security deposit required for the account may change or a security deposit may be required where one was not required previously.

EPCOR may, from time to time, review your credit record or conduct a credit check (including obtaining a credit report) when reviewing a request for new or modified service, determining whether a security deposit is required, or performing collection actions. EPCOR may also report information (such as late payments, missed payments or other defaults) about your account to credit reporting agencies.

EPCOR, at its sole discretion, may accept automatically renewing, irrevocable, unconditional letters of credit from a Customer's bank or a third party guarantee in lieu of cash security, for Commercial Customers or Industrial Customers.

6.3.2 Security Deposit Refunds

Security deposits on all accounts are reviewed annually to determine if the Customer is entitled to a refund or an adjustment as required.

Requests for refund of a security deposit can be made after one (1) year of service for Residential Customers, five (5) years for General Service Customers, and seven (7) years for all other Customers. Refund requests must be made in writing to EPCOR at 39 Beech Street East, Aylmer, Ontario, N5H 3J6, and must include the Customer's address, account number and a statement to the effect that they are applying to have their security deposit refunded or adjusted. EPCOR will refund security deposits by crediting the Customer's account on their next EPCOR bill. At the Customer's request, EPCOR may refund a security deposit through the issuance of a cheque payable to the Customer.

When a Customer discontinues natural gas service with EPCOR, the final billing period must be processed and the account settled in full before the security deposit will be refunded to the Customer.

6.3.3 Interest on Security Deposits

Simple interest will be earned on security deposits held by EPCOR at the Bank of Canada's prime business rate, less 2% or the interest rate prescribed by the OEB. The interest rate will be established quarterly and if the prime business rate is 2% or less at the time of update, the interest rate for the quarter will be 0%.

Interest on security deposits will be calculated and paid out monthly and upon return of the security deposit to the Customer. Interest payments will appear as a credit on the Customer's next bill.

6.3.4 Third Party Security Deposits

Where all or part of a security deposit has been paid by a third party on behalf of a Customer, EPCOR shall return the amount of the security deposit paid by the third party to that third party. This shall apply where and to the extent that:

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

c) there is not an amount overdue for payment by the Customer, as EPCOR is permitted to offset amounts overdue using the security deposit.

6.4 Bill Issuance and Payment

6.4.1 Monthly Bills

Bills are issued to Customers every month. Bills will be mailed to the Customer at the last known address as shown on EPCOR's records. Customers wishing to forward their bills to another address must submit a request to EPCOR in writing. One bill is generated for each service/Meter. EPCOR does not accommodate joint or split billing of accounts for rented properties or third party services. In special situations, EPCOR, at its sole discretion, may combine readings from several Meters into one group bill.

Customers will have the option of using EPCOR's paperless billing option to receive their bills electronically. This environmentally friendly option is secure and convenient. You can sign up to receive paperless billing by calling an EPCOR customer service representative at 1-519-773-5321 or on EPCOR's website at www.epcor.com. New gas Customers will be automatically enrolled in paperless billing unless they request otherwise.

The following items make up your EPCOR natural gas bill:

Natural gas commodity
The gas commodity charge is calculated using the actual cost of gas for the gas you use during the period of time between meter readings (or based on an estimate of the gas used as described in Section 6.2). The commodity rate you are billed at on your EPCOR bill depends upon the commodity purchase choice you have made. If you have not signed a contract with an energy retailer then you are automatically billed at EPCOR's system gas commodity rate for the natural gas commodity portion of your bill. This system gas commodity rate is approved by the OEB. If you have signed a contract with an energy retailer then you are billed at your contracted energy retailer rate for the natural gas commodity portion of your bill.

Delivery to you
These costs are associated with the distribution and transportation of gas from the source to you, including any upstream costs such as upstream recovery, storage and load balancing charges. This includes any carbon tax or similar abatement program, clean fuel, green, or other related charges as applicable to comply with such legislated programs.

Monthly charge
This is an administration charge covering the cost of maintaining gas services and providing billing and customer service.

In addition to the above charges other miscellaneous charges may appear on your bill periodically including transfer/connection fees, late payment charges, and adjustments.

6.4.2 Payment Options

Customers must pay their EPCOR bills, using one of the following options.

6.4.2.1 Automatic Withdrawal Plan

Paying your bill by automatic withdrawal is easy and convenient as your amount due is automatically withdrawn from your bank account on the due date shown on your bill. You can sign up for EPCOR's automatic withdrawal plan by completing an "Automatic Withdrawal Plan Authorization Form" attached at Schedule 2 of these Conditions of Service. This form is also available on EPCOR's website www.epcor.com under "How to Pay Your Bill", in person at EPCOR's office or you can contact an EPCOR customer service representative at 1-519-773-5321 to request a form.

Sufficient funds or bank approved overdraft protection must be available when payment is due to avoid not sufficient funds and/or late payment charges. Dishonored payment withdrawals may result in termination of this payment option. If your banking information changes, new banking information must be provided to EPCOR in writing at least five (5) days prior to your next payment withdrawal date.

A voided personalized cheque or a form certified by your bank displaying your account numbers and the name of your account must be included with all Automatic Withdrawal Plan Authorization Forms and banking information change requests.

6.4.2.2 Online with EPCOR

You may pay your bill online with EPCOR using your debit card or valid credit card (that is accepted by the credit card service provider). Please see EPCOR's website at www.epcor.com for details on how to pay your account online with EPCOR. Payments made by credit card are subject to any convenience or other fees payable to the third party credit card service provider.

6.4.2.3 Through Your Bank

Payments can be made through most banks online, by telephone service or in person through the teller or bank machine. When payments are made through your bank, bills are considered to have been paid on the date the payment is processed by the bank.

6.4.2.4 By mail

Payments by cheque or money order can be mailed to EPCOR's office. Please make your cheque or money order payable to "EPCOR Natural Gas L.P.". Your payment, along with the remittance portion at the top of your bill, can be mailed to EPCOR using the pre-addressed envelope included with your bill statement or by addressing to:

EPCOR
39 Beech Street East
Aylmer, Ontario N5H 3J6

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

6.4.2.5 At the EPCOR Office

Payments may be made in person Monday through Friday during the business hours of 8:00 a.m. and 4:00 p.m. EST or after hours through the quick drop payment slot at the EPCOR office located at 39 Beech Street East, Aylmer, Ontario.

6.4.3 Late Payment

Bills are due when rendered. To avoid late payment charges, your payment must be received by EPCOR by the due date (which is 20 days after the billing date) as shown on your bill. Both the billing date and the due date are displayed on your bill. Payments made after the due date are considered late, and the OEB-approved late payment charge of 1.5% per month or 19.56% per year (effective rate of 0.04896% compounded daily) will be levied. Late payment charges will continue to accrue until the outstanding balance (including any late payment charges) has been paid.

In addition to late payment charges being applied to the outstanding balance, overdue accounts may be subject to disconnection in accordance with EPCOR's process for discontinuance of service for non-payment as outlined in Section 6.8.

EPCOR makes every effort to contact Customers for payment of outstanding amounts. If the account balance remains unpaid despite these efforts, further collection action will be initiated. Customers will be responsible for any additional collection costs incurred by EPCOR or its agent.

6.4.4 Budget Billing Plan

EPCOR offers a budget billing plan designed to equalize the monthly payments for natural gas service throughout the year, thereby avoiding high bills in the winter months. The budget billing plan is available to all Residential Customers and General Service Customers who have established satisfactory credit with EPCOR.

If you are on the budget billing plan, EPCOR will estimate the amount of your bill for natural gas service from May to April based on your historical usage (if available). The estimated total amount for that time period is divided into 12 equal budget billing plan installments. You will then be billed that calculated monthly installment each month from May to the following April. In May of each year:

- your account will be reconciled for the previous 12-month budget billing period; and
- your budget billing plan monthly installment will be recalculated and adjusted based on your most recent 12 months' historical usage.

EPCOR's reconciliation will result in an adjustment being made for the difference between: (a) the monthly budget billing installment payments made by you in the 12-month budget billing period; and (b) the charges for natural gas that would have been incurred based on your actual usage. The adjustment amounts will be reflected on your bill issued for the month of May. Your adjustment will be either a credit, if the total budget billing plan installments you paid were in excess of the actual total natural gas charges incurred, or an amount owing to EPCOR if the actual charges incurred are greater than the sum of budget billing plan installments made.

The estimate completed by EPCOR for the purposes of budget billing plan is not in any way a guarantee or assurance of your total actual natural gas charges. A number of factors can impact your usage and create a variance from the estimate. Significant changes in weather, gas prices, change in gas marketers, or gas use in the home such as additional natural gas appliances, can create a difference between actual gas costs and the installment amounts. EPCOR may at any time submit a revised estimate to you and require your monthly budget billing plan installment be adjusted in order for you to continue on the budget billing plan. You are also encouraged to monitor your actual gas charges compared to your budget billing installments and may request a review of the payments at any time.

Your current budget billing plan applies only to you and your current premises. If you move, the budget billing plan will be terminated and your account reconciled. Adjustments to your account for differences between the actual amount of natural gas used and the budget billing plan installments will be made in the next billing cycle. Should you wish to remain on a budget billing plan, you can request to be set up with one for your new premises.

Customers can inquire about enrolling in the budget billing plan by calling an EPCOR customer service representative at 1-519-773-5321. You are not required to pay through the automatic pre-authorized payment option to enroll in the budget billing plan. You can withdraw from the budget billing plan at any time upon notification to EPCOR. If you withdraw from the budget billing plan before the annual review and reconciliation, the plan will be reviewed and reconciled at that point and your account will be billed or credited for the difference between the budget billing plan instalments paid and the actual total natural gas charges incurred.

6.5 Billing Errors

A retroactive billing adjustment is required to correct the error when a Customer has been billed incorrectly. Billing errors may arise due to a Customer's error or EPCOR's error. Regardless of whether the Customer or EPCOR is responsible for the error, or whether the error results in an over or under-billing, errors will be corrected retroactively for a period of up to two (2) years for Residential Customers. For all other Customers, the error will be corrected retroactively for a period of up to six (6) years.

If you discover an error, please contact an EPCOR customer service representative at 1-519-773-5321. EPCOR will review your account and correct for any validated errors. Adjustments correcting the error retroactively will appear on your next regular bill. In the case of a correction of over-billing, you may request a refund or opt to leave the credit amount on your account to apply to future bills. When the error has resulted in under-billing, EPCOR will work with you to develop an appropriate payment arrangement for the adjustment.

6.6 Allocation of Payments between Gas and Non-Gas Charges

Payments are applied to the charges on your EPCOR bill so that the oldest billed amounts are paid first. In the event that payment is insufficient to cover all charges invoiced in a month, payments will be allocated to natural gas commodity charges first. Late payment charges as outlined in Section 6.4.3 will be calculated on any balance that remains outstanding past the bill due date.

6.7 Discontinuance of Gas Delivery - Customer Initiated

6.7.1 Temporary Discontinuance of Service

Customers may request a temporary disconnection of their gas service. Customers must continue to pay the monthly fixed charge during the period service is temporarily disconnected, as well as the reconnection fee as described in Schedule 1.

6.7.2 Discontinuance of Service

Customers are bound by these Conditions of Service and are obligated to pay for all charges on their EPCOR bill, including late payment charges, until EPCOR has processed and accepted the Customer's request for discontinuance of service and the supply of gas has been terminated by EPCOR. Customers shall provide EPCOR with 15 days' notice for any requested discontinuance.

6.8 Discontinuance of Service for Non-payment

Bills are due when rendered and if any charges remain unpaid after the due date shown on the bill, EPCOR has the right to discontinue delivery of gas service. Customers who are not able to make full payment by the due date shown on their bill should contact EPCOR to make alternative payment arrangements. If a Customer does not contact EPCOR and establish alternative payment arrangements or fails to make a payment required by their negotiated payment arrangement, EPCOR has the right to discontinue service upon providing two (2) days' notice in writing to the Customer.

While the amount of time prior to the discontinuance of service that notice is given may vary depending on the circumstances, a disconnection notice is typically mailed out 14 days in advance of the disconnection. An EPCOR representative will attempt to contact the Customer two (2) days before disconnection, and a hand-delivered notice is provided to the Customer at the time of disconnection.

Customers can avoid discontinuance of service by providing EPCOR with verification that the balance due on their account has been paid in full prior to service disconnection.

If you are seeking payment assistance through a registered charity, government agency, social service agency or a third party, see Section 6.11 for information on EPCOR's customer service rules for eligible low-income customers.

Prior to reconnection of service, Customers disconnected for non-payment will be charged the reconnection fee as described in Schedule 1. Once payment in full is received by EPCOR, including any reconnection charges, security deposits and arears amounts, EPCOR will arrange a suitable time within 48 hours for EPCOR to visit the home or business to reconnect the gas service and relight and inspect all gas appliances.

An increase in the security deposit amount may also be required for Customers who have been disconnected for non-payment.

6.9 Discontinuance of Service for Causes Other than Non-payment

In addition to service interruptions for maintenance and other reasons outlined in Section 2.1, EPCOR may discontinue natural gas service to a Customer at any time for emergency or safety reasons including:

a) the presence of a gas leak or potential safety issue;
b) when there is evidence of fraudulent use of gas;
c) where EPCOR has reason to believe a hazardous condition exists on the premises or may develop;
d) for use of gas for any purpose other than that described in the service application, contract, Rate Schedule or these Conditions of Service;
e) when a gas installation contravenes the provisions of the *Technical Standards and Safety Act*, its associated regulations or any other applicable legislation;
f) where EPCOR is refused lawful access to the premises; and,
g) when a Customer has tampered with, damaged or destroyed EPCOR’s property.

Except for discontinuance for the presence of a gas leak or a potential safety issue, a reconnection fee will be charged to the Customer(s) upon reconnection of gas service for the above reasons in this Section 6.9.

6.10 Arrears Management Programs

EPCOR will work with Customers who are unable to pay their entire bill to find mutually agreeable payment arrangements, taking into consideration the Customer’s specific circumstances. Customers requesting payment assistance can call an EPCOR customer service representative at 1-519-773-5321 to discuss options.

EPCOR will contact Customers when a payment required by their negotiated payment arrangements has been missed and EPCOR has not received prior notification. If a Customer fails to make an agreed upon payment, their negotiated payment arrangement may be cancelled.

Additional financial assistance is also available to eligible low-income Customers who are having difficulty paying their bill or meeting their negotiated payment arrangement in place with EPCOR.

Section 6.11 below provides information on additional support available for EPCOR's eligible low-income Customers.

6.11 Customer Service for Eligible Low-Income Customers

The Low-Income Energy Assistance Program ("LEAP") developed by the OEB provides assistance for payment of natural gas bills by eligible low-income Customers. The program includes emergency financial assistance and the application of special customer service practices and standards. To qualify for LEAP, Customers must meet the income eligibility criteria as defined by the OEB. LEAP emergency financial assistance is administered through a social service agency, and EPCOR has partnered with Ontario Works in Bruce County for this service. More information on the LEAP program is available on the OEB's website at www.oeb.ca.

The following customer service practices and standards are available to Customers who are eligible low-income Customers as determined by Ontario Works in Bruce County:

a) The security deposit requirement will be waived, provided the Customer:
   i. is enrolled in the budget billing plan; and,
   ii. has not had gas service disconnected due to non-payment within the past two (2) years.
b) If a Customer is actively working with the social service agency to secure emergency financial assistance, EPCOR will suspend collection action for non-payment of account, including discontinuance of service, for 21 days before additional collection action will be taken for non-payment.
c) If a Customer requires a negotiated payment arrangement to manage payment of their account balance, EPCOR will waive their late payment charges on the payment arrangement balance for the duration of the arrangement, provided that the terms of the arrangement are kept. If the Customer fails to make an agreed upon payment under the negotiated payment arrangement, the Customer may not be entitled to have late payment charges waived on any future arrears payment arrangements.

For the purposes of the customer service practices and standards for eligible low-income Customers, a Customer's eligible low-income Customer status will remain on their account for two (2) years from the date EPCOR was notified that the Customer qualified.

To determine if you qualify for LEAP, please contact:

Ontario Works – Bruce County at 519-881-0431 or 1-800-265-3005

6.12 Management of Customer Accounts

Conducting business with a high degree of integrity and in an ethical manner is important to EPCOR. These values are applied to EPCOR's interactions with its Customers and to the standards of protection of their personal information. EPCOR is committed to respecting your privacy and complying with applicable legislation. EPCOR treats all Customer information as strictly confidential. EPCOR will not disclose, sell, lease or trade your information unless you authorize us to do so, or it is required or permitted by law.

Your account with EPCOR contains private information about you including your address, phone number, current balance and payment details. Prior to discussing any account specific information, EPCOR will verify the identity of a Customer and to do so, Customers will be required to correctly answer confirmatory questions. In accordance with applicable privacy laws, any personal information related to the account will only be shared with the Customer(s) named on the account, unless written consent has been provided by the Customer named as the primary on the account. To provide consent allowing another person or a third party to discuss your account details with EPCOR, a completed EPCOR Customer Information Consent form must be provided to EPCOR. The EPCOR Customer Information Consent form is attached at Schedule 2 of these Conditions of Service or on the EPCOR website www.epcor.com under “Privacy Policy”, in person at EPCOR’s office or by contacting an EPCOR customer service representative at 1-519-773-5321 to request a form.

EPCOR may provide the Landlord of a rented property with notice of a pending disconnection if the service to the premises is to be discontinued for any reason.

More information on EPCOR’s Privacy Policy is available on the EPCOR website www.epcor.com under “Privacy Policy”.

6.13 Management of Landlord/Tenant Accounts

EPCOR records directions received from Landlords on how to manage accounts at rented properties in between tenants. In the absence of any specific direction, EPCOR will continue to supply gas to the premises and will send the bills to the service address in a generic name. In the event of non-payment, regular non-payment, collection and discontinuance of supply processes will be followed.

If you are a Landlord, please contact an EPCOR customer service representative at 1-519-773-5321 to provide EPCOR with direction on how to manage the accounts for your rental properties. The following two options are available:

Option 1: Continued Service

The Landlord authorizes EPCOR to bill the service to the Landlord in between tenants. This means the Landlord pays for continued service until a new tenant assumes responsibility for the natural gas account.

Option 2: No Service

The Landlord authorizes EPCOR to disconnect the gas service when there is no active account holder. With this option, the Landlord is responsible for any reconnection fees and assumes all responsibility and liability for any damages which may occur as a result of the service being disconnected.

If the Landlord for the premises changes, the incoming Landlord is responsible for notifying EPCOR of the change and updating the direction on how to manage the account. If EPCOR is not contacted by the new Landlord, the direction received from the previous Landlord will continue to remain in force.

6.14 Customer Service

6.14.1 Customer Service Process

Step 1: Contact EPCOR

Call EPCOR's office at 1-519-773-5321 Monday through Friday between 8:00 a.m. and 4:00 p.m. EST and speak with a customer service representative. A trained EPCOR customer service representative will be available to help answer your questions.

You may also send your question or concern by email to gas@epcor.com.

Step 2: Escalating your Concern

If you feel that your questions are not being fully addressed or you have a problem or concern that has not been satisfactorily resolved by EPCOR's customer service representative, please ask to speak with a supervisor. You may be required to leave your name and a phone number where you can be contacted in order for someone to return your call. An EPCOR representative will get back to you within two (2) business days.

Step 3: Submit your Complaint in Writing

Unless otherwise agreed to by the customer, EPCOR will respond to all written customer complaints in writing within ten (10) business days of receipt. Written complaints can be mailed to:

EPCOR
39 Beech Street East
Aylmer, Ontario N5H 3J6

6.14.2 Social Media and Media Questions

EPCOR is committed to respecting your privacy while complying with applicable legislation and treats all Customer information as strictly confidential. Without a signed privacy waiver, EPCOR cannot publicly provide your account information to media (or anyone else) regardless of the issue or media attention.

If you post a question or comment about your EPCOR account on social media, EPCOR cannot publicly provide information about your situation unless you have provided a signed waiver allowing EPCOR to do so. In this situation, EPCOR may not publicly respond to your social media post, but may instead attempt to contact you via other means.

Appendix A - Definition of Terms

The following meanings for the specified terms shall apply in this document regardless of whether the term is capitalized in the document:

Contract Rate Customer – A Customer that has entered into a specific contract with EPCOR for the provision of their natural gas distribution services.

Commercial Customer – A Customer who is engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions).

Customer – An individual, group of individuals, corporation responsible for the receipt and payment of goods and/or services provided by EPCOR.

EPCOR Rate Schedules – Are the OEB-approved schedules in effect at any given time, that specify the eligibility criteria for each class of Customer, the rates charged for gas supplied to EPCOR's various Customer classes, and the terms under which gas service is provided.

Force Majeure – means any event that wholly or partly prevents or delays performance or affects any obligations under these Conditions of Service to the extent such event is beyond the reasonable control of EPCOR, including but not limited to the following:

a) acts of God such as fires, explosions, floods, tornadoes, lightning and storms or wind of sufficient intensity to prevent safe performance;
b) severe weather;
c) strikes and other labour disputes (including collective bargaining disputes and lockouts);
d) war (declared or undeclared), terrorism or other armed conflict;
e) sabotage or vandalism;
f) changes in applicable law;
g) actions of any relevant federal, provincial, regional, municipal government or other regulatory authority;
h) damage, breakdown, accident, breakage or loss of any kind to the pipeline, equipment or property;
i) the necessity for maintaining, making repairs to or alterations of the pipeline or equipment;
j) interruption and/or curtailment by an upstream gas transporter;
k) riot or similar civil disturbance or commotion;
l) depletion or shortage of gas supply; and,
m) order of any legislative body or duly constituted authority.

Gas Appliance - A device that consumes or is intended to consume gas and is certified or approved as acceptable for use by the applicable governmental authority.

General Service Customer – A Commercial Customer or Industrial Customer who is not a Contract Rate Customer and whose gas distribution service is not seasonal.

Industrial Customer – A Customer who is engaged in a process which creates or changes raw or unfinished materials into another form or product, or who change or complete a semi-finished material into a finished form.

Landlord – The owner, landlord or property management company of a rented property.

Main – The pipe that is used to carry natural gas to a service.

Main Extension – The addition of pipe to an existing Main to serve new Customers.

Meter – A device owned by EPCOR and approved by the appropriate governmental authority and installed to measure the volume of gas delivered to the customer.

Month or Monthly – For the purposes of calculating Customers' accounts, is a period of approximately 30 days.

Residential Customer – A Customer who is supplied for residential purposes in a single-family dwelling or building, or in an individual flat or apartment within a multiple family dwelling or building or a portion of a building occupied as the home, residence, or sleeping place of one or more persons. Included in this customer class are multi-residential services which supply buildings used for residential purposes that supply two or more families served as a single Customer under one account.

Service Lateral – Piping and associated fittings that convey gas from a Main to the Meter. Where gas pressure regulation is necessary, the service regulator shall form part of the service.

Schedule 1 – Service Charges and Miscellaneous Charges

EPCOR's fees and rates related to Service and Miscellaneous charges are subject to amendment from time to time as approved by the OEB. These fees and rate can be found in the Schedule of Miscellaneous and Service Charges included in EPCOR's current Rate Schedules. All rates, fees, and service charges are subject to HST or other sales tax as applicable. To find the most recent Rate Schedule, please visit www.oeb.com, call our customer service representative at 519- 519-773-5321 or email at gas@epcor.com.

Service Charges

Service work performed by EPCOR will be charged on a time and materials basis. A minimum labour charge will be applied to all service work of up to 60 minutes. Each additional hour (or part thereof) is charged additional fees. The minimum labour charge and hourly rates differ for work performed during EPCOR's normal working and outside of normal working hours.

Emergency Repairs

In the case of emergency repairs, the Customer or at-fault party will be charged time and materials at the approved service rates described above. In addition, such emergency repairs may also be subject to additional charges for work performed by contractors and other EPCOR staff including management/supervisory staff. Note that if repairs are required as a result of illegal excavation practices by a contractor, the associated service charges will be billed to the Customer for whom the contractor was performing the work.

Miscellaneous Charges

Charges for the following miscellaneous items are currently in effect:

- Returned Cheque/Payment - each instance that a cheque or pre-authorized payment request is returned as not payable for any reason will attract a returned cheque/payment charge.
- Replies to a request for account information from authorized party
- Bill Reprint/Statement Print Requests
- Consumption Summary Requests
- Customer Transfer/Connection Charge

Reconnection Charges

Each instance of reconnection of service for the following reasons are subject to a reconnection fee:

- discontinuance of service for non-payment;
- temporary discontinuance of service;
- discontinuance/reconnection for the purpose of Meter testing at the Customer's request where it is determined that the Meter meets regulated accuracy requirements; and,
- any discontinuance listed in Section 6.9 other than if the discontinuance is the result of the presence of a gas leak or potential safety issue in your neighborhood.

Inactive Account Charge

If a Customer does not have any natural gas consumption within 12 months of installation of a new gas service, they will be required to reimburse EPCOR for any service line installation costs not covered by any Service Lateral installation fee charged at the time of installation. The inactive account charge may be based on the costs EPCOR actually incurred for the service or on EPCOR's average installation cost for the service type.

Schedule 2 – Forms

Attached to this Schedule are the following forms:

- Application for Natural Gas Service
- Meter Size and Location Request Form
- Automatic Withdrawal Plan Authorization Form
- EPCOR Customer Information Consent

EPCOR Natural Gas Limited Partnership

The Application for Natural Gas Service must be completed in full for all new accounts with EPCOR Natural Gas Limited Partnership ("EPCOR" or "the Company"). If the installation of a new service lateral or meter is required in order for EPCOR to provide natural gas service to the Premises, the Meter Size and Location Request Form attached as Appendix A must be completed and signed by the owner of the Premises, and returned to EPCOR along with the completed Application for Natural Gas Service.

Date of Application:_________________________ Required Service Date:_____________________ 20______

☐ Residential ☐ Commercial ☐ Industrial ☐ Seasonal

Service Information

Service Address for New Account (Premises)

Civic #:	Street Name:	Apt.Unit #:	Lot #:	Concession #:

Municipality, Town or City:	Province:	Postal Code:	Telephone Number:	Fax Number:

Service Type

☐ New Service Line* ☐ Meter Only* ☐ New Construction* ☐ Service Reactivation (new account on existing service)

* Please complete the Meter Size and Location Request Form in Appendix A and return to EPCOR with the completed Application for Natural Gas Service.

Account Holder (Customer) Information

Primary Account Holder

Name (last name, first name or company name):	Email Address:	Date of Birth:

Cell Phone #:	Home Phone #:	Daytime Phone #	☐ Owner ☐ Tenant*	* Please Complete Landlord Information section below

Previous Address:

Secondary Account Holder

Name (last name, first name or company name):	Email Address:	Date of Birth:

Cell Phone #:	Home Phone #:	Daytime Phone #	Relationship to Primary Acct Holder:

Emergency Contact Information - Nearest Relative Not Living with the Customer

Name (last name, first name):	Relationship:	Address:	Telephone Number:
Name (last name, first name):	Relationship:	Address:	Telephone Number:

Billing Address (If Different from Premises Address Above)

Billing Address:

Apt.Unit #:	Municipality, Town or City:	Province:	Postal Code:	

Landlord Information

Name (last name, first name or company name):	Address:	Telephone Number:

Terms and Conditions for Natural Gas Service

The following terms and conditions apply to the natural gas service with EPCOR and therefore the applicant, account holder or owner as applicable ("Customer"), in applying to EPCOR for natural gas service at the Premises acknowledges and agrees:

1. To pay all rates, fees or charges due to the Company by the dates indicated for payment on EPCOR's monthly bills including any late payment charges (monthly bills are due when rendered and a late payment penalty will be charged when a monthly bill is left unpaid after the due date indicated on the bills) from the date of this application until either:
    a) the written notice to discontinue the supply of natural gas to the Premises is received by EPCOR and a reasonable opportunity has been given to EPCOR to enter the Premises for the purpose of discontinuing the supply; or,
    b) confirmation has been received by EPCOR that a new account holder assumes the benefits and responsibilities for payment of the account;

2. That a meter connection will be established immediately after the installation of the service line at the Premises and will be subject to the monthly fixed charge from that date;

3. That natural gas supplied to the Premises is to be drawn through a meter installed by the Company. The Customer is responsible for the protection of all metering equipment necessary for the supply of gas and for keeping it accessible at all times. If the meter should fail to register the quantity of gas consumed or if EPCOR is not able to gain access to read the meter, the Company will estimate a reading for the purposes of updating the Customer's account and issuing bills;

4. That EPCOR, before supplying, or as a condition of continuing to supply, natural gas to the Premises, may require the Customer to give reasonable security for the payment of the proper charges;

5. That the Company, upon providing the Customer with 48 hours notice may discontinue service of natural gas, or lock or remove the meter for non-payment of bills (including late penalty charges) when due;

6. To immediately notify EPCOR of any leakage or escape of natural gas on the Premises by calling the 24 hour emergency number at 1-519-773-5321. EPCOR shall not be liable to the Customer for any damages and the Customer shall indemnify EPCOR from and against all loss, cost, damages, injury, or expense associated with any injury or damage to persons or property arising, either directly or indirectly, from or incidental to the escape of gas or products of combustion of gas from piping, controls, appliances or appliances that are on the outlet side of the meter at the Premises;

7. That EPCOR and/or its authorized agents shall have access to the customer's premises at all reasonable times and upon reasonable notice, unless in case of an emergency, as determined by EPCOR in its sole discretion, EPCOR is unable to provide reasonable notice, for the purposes of inspecting, repairing, testing, replacing, altering or disconnecting any meter, service pipe, appliance or equipment used in connection with gas service within or outside the premises;

8. That the Company, its directors, officers, agents, employees and representatives ("EPCOR Parties") shall not be liable to the Customer, its directors, officers, agents, employees and representatives ("Customer Parties") for any loss, injury, damage, expense, charge, cost or liability of any kind suffered or incurred by the Customer Parties, or any of them, whether of a direct, indirect, special or consequential nature, howsoever or whensoever caused, and whether in any way caused by or resulting from the acts or omissions of the EPCOR Parties, or any of them, except for direct property damages incurred by the Customer as a direct result of a breach of the terms and conditions outlined in this Application for Natural Gas Service, EPCOR's Conditions of Service or the applicable agreement between EPCOR and the Customer, or other act or omission by an EPCOR Party, which breach or other act or omission is caused by the negligence or wilful act or omission of harm of such EPCOR Party. Any liability under this section will be limited to an amount in proportion to the degree to which the EPCOR Party acting negligently or wilfully is determined to be at fault. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct property damage" shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of capital, and loss of use of any facilities or property, or any other similar damage or loss whatsoever.

9. That in addition to any other liability provisions set out the terms and conditions of this Application for Natural Gas Service, EPCOR's Conditions of Service or the applicable agreement between EPCOR and the Customer, a Customer Party shall be liable for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by EPCOR Parties, whether of a direct or indirect nature, caused by or arising from any acts or omissions of an Customer Party that result in a breach of the terms and conditions outlined in this Application for Natural Gas Service, EPCOR's Conditions of Service or the applicable agreement between EPCOR and the Customer, or any negligent or wilful acts or omissions of harm of a Customer Party. Any liability under this section will be limited to an amount in proportion to the degree to which the Customer Party is at fault.

10. The Customer shall not install or allow to be installed on property owned or controlled by the Customer any temporary or permanent structures that could interfere with the proper and safe operation of EPCOR's gas pipeline system or result in non-compliance with applicable statutes, regulations, standards and codes. EPCOR shall not be liable for any damage to any structure or improvement erected, installed or placed in contravention of this Application for Natural Gas Service resulting from the maintenance of such gas line or service line.

11. That the current transfer/connection charge in effect at the time of this Application for Natural Gas Service will be charged to the Customer's account on the first billing;

12. That in the event the Customer does not have any natural gas consumption within 12 months of installation of a new gas service, the Customer will be required to reimburse EPCOR for any service line installation costs not covered by the service lateral installation fee charged at the time of installation. The inactive account charge may be based on the costs EPCOR actually incurred for the service or on EPCOR's average installation cost for the service type;

13. That the Company will use any personal information provided in this Application for Natural Gas Service in strict accordance with EPCOR's Privacy Policy and the processes outlined in EPCOR's Conditions of Service; and,

14. To comply with and be bound by the foregoing as well as the terms outlined in EPCOR's Conditions of Service, and any other applicable rules and regulations of the Company as established from time to time.

I, the undersigned, am applying to EPCOR for natural gas service to be supplied to the Service/Premises address described above. I request to have an account set up with EPCOR in my name. I understand that EPCOR may perform a reference or background check based on the information provided in this form and I warrant that all of the information entered above is correct. I acknowledge that I have read, understand and agree to comply with the terms and conditions set out in this Application for Natural Gas Service.

Customer's Name (print) _________________ Customer's Signature _________________ Date__________

Customer's Name (print) _________________ Customer's Signature _________________ Date__________

** Wherever I/my/me is used it is inferred we/our/us if there is more than one signature.*

If attaching a Meter Size and Location Request Form , the Premises owner(s) is required to provide their initials in this box acknowledging the terms and conditions of this Application for Natural Gas Service as applying to the Premises and the owner.

Owner(s) Initials

For Office Use Only:
Deposit received: $__________ Deposit received by__________________________

Required for New Service Line or Meter Installations only

This form must be completed and returned to EPCOR along with the completed Application for Natural Gas Service. Please ensure the form is signed on page 2 by the owner of the Premises and the owner's initials are provided on page 3 of the Application for Natural Gas Service.

Date:______________________ EPCOR Account #:___________________

Service/Premises Information

Civic #:_________________ Street Name:____ Apt/Unit #:________________

Municipality, Town or City:______________________________________ Postal Code:________________________________

Premises Owner

Name:____ Email:____

Home Phone:____ Cell Phone:____

Builder / Contractor / Installer

Company Name:____________________________________ Contact:____

Phone:___________________________ Fax:____________________________ Email:______________________

Service Installation

☐ Residential ☐ Commercial ☐ Industrial

Required Date:_____________________ Occupancy Date:____________________ Building Square Footage:_____________

☐ Single ☐ Row Housing ☐ Duplex/4 Plex ☐ Multi-Meter Set, # of Meters_______________

Natural Gas Equipment & Total BTU Input Required

Equipment	Quantity	New BTU	Future BTU	Notes
Heating				
Water Heating				
Cooking				
Fireplace				
In Floor Heating				
BBQ				
Pool Heater				
Generator				
Construction Heat				
Industrial Process				
Total Load:				

Gas Pressure: ☐ 7" w.c (1.75kpa) is the standard delivery pressure ☐ 14 kpa ☐ 35 kpa ☐ 70 kpa ☐ Other _____ kpa

Service Length & Location (required)

Length from property line to meter location (m):__________

Meter location is on what wall as viewed from the street?

Front ☐ Right ☐ Left ☐ Other ☐ _______________

Distance from nearest front corner (m):___________

**** For residential applications the meter location must be provided above or marked on the foundation or EPCOR will set the meter, 2 meters back from the front corner of the dwelling.** **Time to complete:** _____________

Include north arrow & meter location(s)

House/Building

Identify:

☐ Hydro Lines
☐ Propane/Oil Tanks
☐ Septic
☐ Water Wells
☐ Irrigation
☐ Comm. Cables
☐ Drains
☐ Other _________

Service Line and Meter Location Costs

EPCOR shall complete a construction estimate for the work required to install the natural gas service lateral extending from the property line to the meter location selected by the Company. The minimum fee for installation of a natural gas Service Lateral is outlined in EPCOR's Schedule of Miscellaneous and Service Charges included in its Rate Schedules and includes up to 20 meters of pipe. Additional fees may be charged if the length of pipe required to bring the Service Lateral to the Meter location exceeds the 20 meter length EPCOR uses to set this fee.

EPCOR will determine the location at which the service will enter a building with the normal point of entry being through the wall nearest to the gas manifold. The Company may, at its sole discretion, accommodate requests made by an applicant regarding the location of the service or other specific requirements and in such cases the applicant will be responsible for any additional costs associated with the request.

All fees for the service lateral installation must be paid in full before EPCOR will commence work on the installation. If the customer at the premises does not have any natural gas consumption within 12 months of installation of a new gas service, the owner will be required to reimburse EPCOR for any service line installation costs not covered by the service lateral installation fee charged at the time of installation.

Owner Acknowledgement

I, the undersigned, am the owner of the property at the Service/Premises address described above and on the attached Application for Natural Gas Service (the "Premises") and hereby request EPCOR to install a service line and meter for the supply of natural gas to the Premises. I warrant that all of the information entered above is correct and that all persons whose signature(s) are required or have ownership of the Premises have signed this application. I acknowledge that I have read, understand and agree to comply with the terms and conditions set out in this Meter Size and Location Request Form and in the Application for Natural Gas Service to which this form has been attached.

Owner's Name (print) __________________ Owner's Signature ______________________ Date___________

Owner's Name (print) __________________ Owner's Signature ______________________ Date___________

In addition to this acknowledgement, the owner(s) must initial page 3 of the Application for Natural Gas Service.

** Wherever I/my/me is used it is inferred we/our/us if there is more than one signature.*

AUTOMATIC WITHDRAWAL PLAN

EPCOR Natural Gas Limited Partnership

A CONVENIENT WAY TO PAY YOUR EPCOR BILL AND MANAGE YOUR MONTHLY PAYMENT

With the **Automatic Withdrawal Plan**, your monthly natural gas bill payment is withdrawn from your bank account on the due date on your bill. This amount is then credited to your EPCOR account. You never have to worry about waiting in payment lines, forgetting to pay your bill on time or making payment arrangements when you're away from home.

HOW DO I APPLY?

Complete and sign the EPCOR Payment Plan Application form. Attach a blank, personalized cheque marked "VOID". If you do not have a cheque, you can have your bank complete and verify the required account information on the application form. Mail the application and void cheque to the location noted at the bottom of this page.

Ensure your current utility bill is paid in full at the time you enroll. Continue to make payments in your usual manner until the "AUTO PAYMENT, DO NOT PAY" message appears on the remittance portion of your bill.

WHEN IS PAYMENT WITHDRAWN FROM MY BANK ACCOUNT?

You will continue to receive a utility bill each month. Payment withdrawal will occur on the due date of your utility bill as displayed on your bill. You should ensure these funds are available in your bank account at least two working days prior to and after the scheduled withdrawal date.

Please Note: Sufficient funds or bank approved overdraft protection must be available when payment is due to avoid not sufficient funds and/or late payment charges. Dishonored payment withdrawals may result in termination of this payment option.

WHAT IF MY BANK ACCOUNT CHANGES?

Simply advise us in writing at least five (5) working days **prior** to your next payment withdrawal date and include your "voided" personalized cheque or a form certified by your bank displaying your new account number. We'll do the rest!

WHO CAN I CONTACT FOR MORE INFORMATION?

CONTACT EPCOR

Mail to: EPCOR
39 Beech Street E
Aylmer, Ontario N5H 3J6

Online: www.epcor.com

By Phone: 1-519-773-5321

Email to: gas@epcor.com

AUTOMATIC WITHDRAWAL PLAN TERMS AND CONDITIONS

I* authorize EPCOR Natural Gas Limited Partnership (EPCOR) and the financial institution designated (or any other financial institution I may authorize at any time) to begin deductions as per my instructions for monthly recurring variable payments and/or one-time payments from time to time, for payment of all charges arising under my EPCOR account(s). I hereby authorize EPCOR to debit my bank account as indicated on the attached "void" cheque included with my application or my savings account as indicated on the application form.

Regular monthly payments for the full amount of services delivered will be debited to my account on the due date of each EPCOR statement. EPCOR will provide 10 days written notice of the amount of each regular debit. EPCOR will obtain my authorization for any other one-time or sporadic debits.

I will notify EPCOR of any changes in the account information in writing at least five (5) business days prior to the next due date of the automatic withdrawal.

This authority is to remain in effect until EPCOR has received written notification from me of its change or termination. This notification must be received at least five (5) business days before the next debit is scheduled at the address provided below. I may obtain a sample cancellation form or more information on my right to cancel an Automatic Withdrawal Agreement at my financial institution or by visiting **www.payments.ca**.

Cancellation of this authorization does not terminate my EPCOR service but only affects my method of payment. EPCOR may terminate this authorization at any time verbally or by written notice to me at the phone number or address listed on the utility account shown on my application form. I acknowledge that EPCOR may charge my utility account with a not sufficient funds and/or late payment charges for each dishonored payment as it occurs, and that it may also result in termination of my participation in the Automatic Withdrawal Plan.

I have certain recourse rights if any debit does not comply with this Agreement. For example, I have the right to receive reimbursement for any debit that is not authorized or is not consistent with this Automatic Withdrawal Agreement. To obtain a form for a Reimbursement Claim, or for more information on my recourse rights, I may contact our financial institution or visit **www.payments.ca**.

I acknowledge that provision and delivery of this authorization to EPCOR constitutes delivery by me to my financial institution.

An Automatic Withdrawal adjustment will be made only under the following conditions:

1. Authorization was not provided to EPCOR.
2. Payment withdrawal was not processed in accordance with my authorization agreement.
3. Authorization has been cancelled/revoked and I have chosen another method of payment.
4. Any payment withdrawal dispute must be made within 90 days of the disputed debit being posted to my account.

I understand I will continue to make payments on my account in my usual manner until the automatic withdrawal message appears on my bill.

I consent to EPCOR collecting, using and disclosing this information for the purpose of establishing automatic payment withdrawals, which will be applied against my EPCOR account.

** Wherever I/my/me is used it is inferred we/our/us if there is more than one signature.*

AUTOMATIC WITHDRAWAL PLAN AUTHORIZATION FORM

Name on EPCOR Account ____________________

EPCOR Service Address: ____________________

Phone (home): ____________________ Phone (work): ____________________

Mailing Address: ____________________
(If different from service address)

Contact Person: ____________________ Phone: ____________________
(If different from account holder)

EPCOR Account Number: ____________________ Category ☐ Personal ☐ Business

Transit # ______ __ __ __ __ Bank # _____ __ __ Account # _____ __ __ __ __ __ __ __ __ __ __ __ __

Automatic Withdrawal Agreement:
I, the undersigned, authorize EPCOR to withdraw funds from the bank account indicated on the attached “void” cheque or from the bank account information supplied above to cover payments due by me to EPCOR for outstanding charges for utility services provided to me. I acknowledge that I have read and understood all provisions contained in the Terms and Conditions and that I have received a copy. I warrant that all persons whose signature(s) are required or authorized to sign on this bank account have signed this application. I consent to EPCOR collecting, using and disclosing this information for the purpose of establishing automatic withdrawals, which will be applied against my EPCOR account.

Authorized Signature(s): (as you would sign your cheque)

Name ____________________ Signature ____________________ Date ____________

Name ____________________ Signature ____________________ Date ____________

Please remember to include:
- Your completed application form
- A personalized cheque marked “void” (if chequing account selected)
- ***Continue to make payments on your account in your usual manner until the automatic withdrawal message appears on your utility bill.***

Note that at least one name on the cheque must be the same as the name on your EPCOR bill so the bank can ensure this agreement it valid.

** Wherever I/my/me is used it is inferred we/our/us if there is more than one signature.*

CONTACT EPCOR

Mail to: EPCOR
39 Beech Street E
Aylmer, Ontario N5H 3J6

To learn more visit: www.epcor.com

Email to: gas@epcor.com

For Office Use Only:

☐ DPAC ☐ Change in Banking Information ☐ New EPCOR PAC Customer

EPCOR Customer Information Consent

EPCOR is committed to protecting your personal information. For this reason, we require your consent prior to disclosing your EPCOR account details to any third party. To ensure your request is processed efficiently, please provide the following information and sign the authorization below (please print clearly).

EPCOR Account Number:	
Account holder Name(s):	
Individual(s) or **organization**(s) authorized to receive information: *and/or* **Energy Retailer**(s) authorized to receive information (please be specific):	
Information you would like EPCOR to provide (please be specific):	
This consent is valid until (please specify date):	

AUTHORIZATION

I/we, the undersigned, hereby authorize and direct EPCOR to release the information identified above to the party or parties specified in this form. I/we acknowledge and agree that EPCOR has no control over, and shall bear no responsibility or liability for, the actions of a third party with respect to personal information released by EPCOR in accordance with this consent form.

DATE: ______________________

Account holder #1 Name: ______________________

Signature: ______________________

Account holder #2 Name: ______________________
(If applicable)

Signature: ______________________

PLEASE NOTE*: Where there is more than one account holder, EPCOR may be unable to fully provide all information authorized by this consent, unless all persons named on the account have signed this consent form.*

Delivery instructions for release of personal information:

Name of Individual,
Organization or Company: ______________________

Mailing Address: ______________________

Phone Number: ______________________ Fax Number: ______________________

Email Address: ______________________

Please indicate how your personal information may be transmitted by EPCOR to third parties (check all that apply):

❏ Mail ❏ Phone ❏ Fax ❏ E-mail

EPCOR

8.Staff.26

Reference: Exhibit 8 / Tab 1 / Schedule 2 / Pgs.2-9

Preamble: *The monthly fixed charge for Rate 1 customers which includes residential is proposed at $25 per month.*

Questions:

(a) Please confirm that the $25 per month fixed charge is the highest amongst all gas distributors in Ontario. Please explain the reasons for the high monthly fixed charge.

(b) With respect to the fixed monthly charge across all rate classes, please provide the proportion of customer related costs that will be recovered through the fixed monthly charge?

Responses:

a) Confirmed. The fixed monthly charge for residential customers serviced by Enbridge Gas, Union Gas and EPCOR Natural Gas Limited Partnership effective April 1, 2019 is $20, $21, and $15.50 respectively.

EPCOR has proposed a rate design that recovers a higher proportion of revenue through the fixed monthly charge, and a reduced amount through variable charge. This results in a higher degree of cost certainty for customers and revenue stability for EPCOR Southern Bruce.

EPCOR also reviewed the OEB's policy for electricity distribution rate design and the decision to recover the distribution delivery costs entirely through a fixed monthly charge[1] [2]. EPCOR suggests that several of the benefits noted for electricity distributors, including ensuring that customers pay a greater percent of the fixed cost to delivery natural gas independent of their usage, also applies to the distribution of natural gas. The revenue from the proposed $25 fixed monthly charge recovers 50.5% of the customer related costs for Rate 1 customers. This better aligns with EPCOR's distribution cost structure than a lower fixed monthly charge.

b) The revenue from the fixed monthly charges across all rate classes recovers 51.0% of the customer related charges.

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[1] EB-2012-0410, Board Policy, A New Distribution Rate Design for Residential Electricity Customers
[2] EB-2015-0043, Staff Report to the Board, Rate Design for Commercial and Industrial Electricity Customers Rates to Support an Evolving Energy Sector

9.Staff.27

Reference: Exhibit 9 / Tab 2 / Schedule 1 / Pg.1

Preamble: *The draft Accounting Order for PGCVA, in part, states: "The PGCVA will also record an inventory valuation adjustment every time a recalculated PGCVA Reference Price comes into effect at the beginning of a quarter within the fiscal year."*

Questions:

(a) Please show an example of how the amount for inventory valuation adjustment would be recorded in this account.

(b) Please confirm that only carrying charges related to inventory valuation would be recorded in this account.

(c) Please adjust entry ii) as necessary based on EPCOR Southern Bruce's response to part b) of this question.

The accounting entry i. states: "To record the projected changes in gas cost and prospective recovery of the gas supply deferral accounts approved by the Board:"

(d) Please confirm that it is not the "projected changes" but the difference between actual price and forecast price underpinning the rates that would be recorded in this account.

Responses:

(a) Upon further review, EPCOR believes it would be more appropriate to handle inventory valuation adjustments through a separate account as EPCOR Aylmer does through its Gas Purchase Rebalancing Account (GPRA). Accordingly, in addition to the Purchased Gas Commodity Variance Account (PGCVA) originally proposed, EPCOR proposes to establish a GPRA for its Southern Bruce operations and to handle the calculation and recording of the amounts for these accounts in the same manner as Aylmer[1]. The GPRA account deals with commodity costs which are to be a flow through to the customer aligning with the eligibility criteria of causation and prudence and based on its experience with this account for its Aylmer operations, EPCOR expects the amounts in this account to exceed the materiality threshold of $50,000. A revised draft accounting order for the PGCVA and a draft accounting order for the GPRA have been provided in 9.Staff.39 Attachment 1 reflecting EPCOR's revised proposal in this regard.

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[1] For explanation on the calculation of the amounts and an example see EPCOR's most recent QRAM for the Aylmer (EB-2019-0162)

(b) Carrying charges would be calculated on both the PGCVA and GPRA balances as reflected in the draft Accounting Orders provided in 9.Staff.39 Attachment 1.

(c) See revised draft Accounting Order in 9.Staff.39 Attachment 1.

(d) Confirmed. The difference between the actual price and the forecasted price underpinning the rates (i.e. reference price) applied to the actual volumes purchased would be recorded in the PGCVA. The revised draft Accounting Order provided in 9.Staff.39 Attachment 1 has been updated to reflect this wording.

9.Staff.28

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *2019 Federal Carbon Pricing Program*

Questions:

(a) Please identify and explain EPCOR Southern Bruce' internal processes to ensure it complies with the federal government's Part I of the Greenhouse Gas Pollution Pricing Act (GGPPA) e.g., calculates and reports monthly to the CRA.

(b) Please explain how EPCOR Southern Bruce will manage its own compliance obligation (i.e., its company use volumes related to its office building and natural gas vehicle fleet) under Part I of the GGPPA.

(c) Please provide the bill impact for a typical residential customer.

Responses:

(a) EPCOR Southern Bruce has assigned a point person the responsibility for managing exemption certificates as well as calculating and reporting month-end obligations under Part 1 of the Greenhouse Gas Pollution Pricing Act ("GGPPA"). In the event that the point person is not available to complete the calculation and reporting, the tasks have been cross-trained to ensure coverage.

Each month, EPCOR Southern Bruce will obtain customer and facility delivery volumes from its billing data. Exemption certificates collected from customers will be tracked in EPCOR Southern Bruce' billing system and these accounts will be flagged for exclusion for the purposes of EPCOR Southern Bruce' monthly reporting requirements under Part 1 of the GGPPA. EPCOR Southern Bruce will continue to monitor changes in the Federal Carbon Pricing Program and will modify its processes and systems as needed to ensure ongoing compliance.

(b) In order to comply with the GGPPA tracking requirements, EPCOR Southern Bruce will track company use volumes subject to the Federal Carbon Charge (related to its office buildings and natural gas vehicle fleet) in its financial reporting system. The company use volumes related to its office buildings and natural gas vehicle fleet will be read once a month by the meter readers; same as any other EPCOR customer. This office and vehicle information will be used to separately report and remit the 2019 Fuel Charge for natural gas used for EPCOR Southern Bruce' office building and natural gas vehicle fleet.

(c) The bill impact for existing residential customers with average annual consumption of 2,149 m^3 is an increase of $126.15 per year starting 2020, the first full year of service. The bill impact for new residential customers with average annual consumption of 2,066 m^3 is an increase of $121.27 per year starting 2020, the first full year of service. Please refer to the Table in IR Response 'Enbridge 2 (b)' showing total annual bills for residential customers and a breakdown of all relevant bill components.

9.Staff.29

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *Forecast Customer-Related and Facility-Related Volumes and Associated Costs*

Questions:

(a) Please explain whether EPCOR Southern Bruce is a covered facility under Part II of the GGPPA (i.e., the federal government's Output-Based Pricing System (OBPS)).

i. If yes, please provide EPCOR Southern Bruce' 2019 volume forecast subject to the OBPS.

1. Please identify and explain EPCOR Southern Bruce' reporting requirements under Part II of the GGPPA.
2. Please identify and explain whether there is additional compliance requirements that EPCOR Southern Bruce is required to do under Part II of the GGPPA.
3. Please identify and explain EPCOR Southern Bruce' internal processes to ensure it complies with the federal government's OBPS.
4. Please describe how EPCOR Southern Bruce will manage its own compliance obligation under Part II of the GGPPA.

(b) Please explain whether any volumes of fuel (covered under Part I of the GGPPA) that EPCOR Southern Bruce reports monthly to the CRA will be calculated using estimated volumes. If so, please explain how EPCOR Southern Bruce will reconcile with customers and the CRA when the CRA monthly billed volumes do not accurately reflect the customer's actual monthly consumption.

(c) Draft Regulations Amending the Fuel Charge Regulations dated March 2019 states that greenhouse operators are to receive 80% relief from the Federal Carbon Charge.

i. Has EPCOR Southern Bruce received any Exemption Certificates from commercial greenhouse operators in its service territory?

ii. What is the estimated 2019 volume related to these commercial greenhouse operators. Please explain.

iii. Does EPCOR know whether there are any outstanding exemption certificates? If so, what is the annual quantity of gas that they represent?

Responses:

(a) EPCOR Southern Bruce is not required to register as an "emitter" pursuant to section 57(1) of the GGPPA because EPCOR Southern Bruce is not a person responsible for a "covered facility". EPCOR Southern Bruce has also confirmed with ECCC that it is not required to register as an "emitter" because its facility emissions are below 10,000 tonnes of CO2e.

(b) The volumes of fuel (covered under Part I of the GGPPA) that EPCOR Southern Bruce reports monthly to the Canada Revenue Agency ("CRA") will be the actual volumes billed to customers. There are certain circumstances in which EPCOR Southern Bruce will need to estimate usage due to no access to the meter to read the usage when the account is billed. In such a scenario, EPCOR Southern Bruce' billing system will calculate the estimated usage based on a set formula that uses the usage from the same period from the previous year. When an actual meter read is completed, the billing system will auto-adjust for estimates or errors in reads on the next month's bill of the customer.

In the event that monthly billed volumes reported to the CRA does not accurately reflect the customer's actual monthly consumption, e.g. billing errors, a billing adjustment will be made to correct the amounts charged to the customer, including the charges under the Federal Carbon Pricing Program. EPCOR Southern Bruce' subsequent monthly remittance to the CRA will reflect any volumetric corrections.

(c)

i. EPCOR Southern Bruce has not received any Exemption Certificates from commercial greenhouse operators.

ii. 0 m3 for commercial greenhouse operators for 2019.

Upon receipt of any Exemption Certificates in 2020, the first full year of service, EPCOR Southern Bruce will estimate and modify the customer related volume forecast accordingly.

iii. At this time EPCOR Southern Bruce is not aware of any outstanding exemption certificates. In the future, EPCOR Southern Bruce will apply accepted practice communication methods, such as bill inserts, to notify customers including greenhouse operators of the partial relief available through an Exemption Certificate.

9.Staff.30

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *Administration Costs – Staffing Resources*

Questions:

(a) What are the estimated administrative costs to administer the Federal Carbon Pricing Program?

(b) What are the estimated internal and external resources required?

Responses:

(a) EPCOR Southern Bruce has provided a forecast of the 2019 and 2020 administrative costs and listed the expected components comprising the administration costs for each year in this response for informational purposes only. EPCOR Southern Bruce proposes to record actual costs incurred in the existing Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA") and will seek recovery of its actual administration costs related to the Greenhouse Gas Pollution Pricing Act ("GGPPA") in a future proceeding.

Forecasted 2019 GGPPA Related Administration Costs ($)

	Expense Category	2019 Forecasted
1	Staffing Resources	5,500
2	Consulting and External Legal	2,000
3	Other	2,500
4	**Total**	**10,000**

Forecasted 2020 GGPPA Related Administration Costs ($)

	Expense Category	2020 Forecasted
1	Billing System Costs	2,500
2	Staffing Resources	68,000
3	Consulting and External Legal	20,000
4	Bad Debt Expense	2,300
5	Customer Communication	2,500
6	Other	2,500
7	**Total**	**97,800**

(b) EPCOR Southern Bruce expects to be able to complete the management, coordination and reporting for the GGPPA using resources internal to EPCOR Utilities Inc. EPCOR Southern Bruce has assigned a point person the responsibility for managing customer exemptions as well as calculating and reporting month-end obligations under Part 1 of the GGPPA. In the event that the point person is not available to complete the calculation and reporting, the tasks have been cross-trained to ensure coverage.

Further, external legal support will be required to support EPCOR Southern Bruce' regulatory filings related to the GGPPA, as well as for the review and interpretation of regulations associated with the GGPPA or other provincial and federal GHG or carbon pricing programs.

EPCOR Southern Bruce does not expect to incur any consulting or audit related fees for the GGPPA or other provincial and federal GHG or carbon pricing programs.

9.Staff.31

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *Administration Costs – Communication Plan*

Questions:

(a) Please explain whether EPCOR Southern Bruce has decided on a methodology to dispose of its 2019 administration costs and identify the proceeding in which these costs will be reviewed and disposed of.

(b) Please explain, to what extent EPCOR Southern Bruce has, to date, informed its customers of the requirement to charge the Federal Carbon Charge and any charges to customer's bills.

i. Please outline any planned communications to inform customers of Federal Carbon Pricing Program.

Responses:

(a) Consistent with EPCOR Natural Gas Limited Partnership's response to EB-2019-0101: 2019 Federal Carbon Pricing Program Application, EPCOR Southern Bruce will await the OEB's directions regarding the disposition of 2019 costs, whether it be through the annual Price Cap IR application, a Federal Carbon Pricing Program-specific application, or such other application or process as the OEB directs.

(b) EPCOR Southern Bruce does not yet have any active customers and billing obligations and therefore EPCOR Southern Bruce has not informed its customers of the requirement to charge the Federal Carbon Charge.

i. During 2020, the first full year of planned service, EPCOR Southern plans to utilize a bill insert to provide customers with information on the GGPPA.

In addition, if this application is approved, EPCOR will inform customers of the changes to their rates and billing to implement the Federal Carbon Charge through the following communication channels:

a) Website content;

b) Bill inserts;

c) Bill notices;

d) Newspaper advertisement;

e) Media messaging (in anticipation of media inquiries);

f) Customer Service staff script (customer FAQs).

9.Staff.32

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *EPCOR Southern Bruce is requesting approval to establish the following three new deferral and variance accounts for use associated with EPCOR Southern Bruce' compliance with the Greenhouse Gas Pollution Pricing Act for its South Bruce operation.*

- *Greenhouse Gas Emissions Administration Deferral Account*
- *Federal Carbon Charge – Customer Variance Account*
- *Federal Carbon Charge – Facility Variance Account*

Questions:

(a) Is EPCOR Southern Bruce seeking to include recovery of the costs associated with the Federal Carbon Pricing Program in rates or is EPCOR Southern Bruce applying for the establishment of deferral accounts for 2019 (as opposed to a variance accounts for customer and facility)?

(b) Please explain whether EPCOR Southern Bruce will be able to separately track costs related to: 1) any provincial GHG or carbon pricing programs and 2) other federal GHG or carbon pricing programs (besides the GGPPA) in the Greenhouse Gas Emissions Administration Deferral Account (GGEADA)? If not, why not? Please explain.

(c) Please explain how each of EPCOR Southern Bruce' three new variance and deferral accounts meet the tests of: Causation, Materiality and Prudence.

Responses:

(a) EPCOR Southern Bruce is seeking recovery of the Fuel Charge as the Federal Carbon Charge from customers in its distribution rates. Contrary to its Aylmer operations, where customer and facility related volumes as well as associated costs were forecasted, EPCOR Southern Bruce first year of service is expected to be in 2020. In the interim, EPCOR Southern Bruce proposes a charge of 3.91 cents/m^3 over volumes from April 1, 2019 to December 31, 2019 and is seeking recovery of the Federal Carbon Charge through rates to be applied to customer bills effective April 1, 2019 (see updated Rates below).

EPCOR Southern Bruce is not an operational utility and does not have building and vehicle usage history. As a result, the Facility Carbon Charge cannot be estimated at this time until 2020, its first full year of service. Once the utility is operational, EPCOR Southern Bruce will seek approval to add the Facility Carbon Charge to the approved delivery charge on customers' bills to recover the GGPPA costs related to company use volumes. EPCOR Southern Bruce proposes to record costs associated with the company use volumes in its variance account (Federal Carbon Charge – Facility Variance Account) and will seek to have such costs disposed of in a future proceeding.

EPCOR NATURAL GAS LIMITED PARTNERSHIP
RATE 1 - General Firm Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are equal to or less than 10,000 m^3 per year.

Rate

Rates per m^3 assume energy content of 38.89MJ/m^3.

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

Monthly Fixed Charge	$25.00	
Delivery Charge		
First 100 m^3 per month	26.3906	¢ per m^3
Next 400 m^3 per month	25.8628	¢ per m^3
Over 500 m^3 per month	25.0869	¢ per m^3
Upstream Charges		
Upstream Recovery charge	1.4779	¢ per m^3
Transportation and Storage charge	2.7054	¢ per m^3
Carbon Charges		
Federal Carbon Charge (if applicable)	3.9100	¢ per m^3
Gas Supply Charge	12.4847	¢ per m^3

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the supplier must qualify as a "gas marketer" under the *Ontario Energy Board Act, 1998*, and must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 6 – Large Volume General Firm Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are greater than 10,000 m^3 per year.

Rate

Rates per m^3 assume energy content of 38.89MJ/m^3.

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

Monthly Fixed Charge	$102.00	
Delivery Charge		
First 1,000 m^3 per month	24.7189	¢ per m^3
Next 6,000 m^3 per month	22.2470	¢ per m^3
Over 7,000 m^3 per month	21.1346	¢ per m^3
Upstream Charges		
Upstream Recovery charge	2.9279	¢ per m^3
Transportation and Storage charge	5.6564	¢ per m^3
Carbon Charges		
Federal Carbon Charge (if applicable)	3.9100	¢ per m^3
Gas Supply Charge	12.4847	¢ per m^3

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 11 - Large Volume Seasonal Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose gas requirements are only during the period of May 1 through December 15 inclusive and are greater than 10,000 m^3.

Rate

Rates per m^3 assume energy content of 38.89MJ/m^3.

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

	May 1 through December 15	
Monthly Fixed Charge	$204.00	
Delivery Charge		
All volumes delivered	15.3546	¢ per m^3
Upstream Charges		
Upstream Recovery charge	0.0353	¢ per m^3
Transportation and Storage charge	1.8215	¢ per m^3
Carbon Charges		
Federal Carbon Charge (if applicable)	3.9100	¢ per m^3
Gas Supply Charge	12.4847	¢ per m^3

Unaccounted for Gas (UFG):

Forecasted UFG is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:

Any volume of gas taken during the period of December 16 through April 30 inclusive shall constitute "Overrun Gas" and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	16.0000	¢ per m^3

Any volume of gas taken during the period of December 16 through April 30 inclusive without EPCOR's approval in advance shall constitute "Unauthorized Overrun Gas". Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges.

Unauthorized Overrun Charge	388.9000	¢ per m^3

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

Nominations:

Union Gas Limited will be the "Upstream Service Provider" to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate as set out in this Rate Schedule.

The nomination calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG)]

Customers may change daily nominations based on the nomination windows within a day as defined by EPCOR's agreement with the Upstream Service Provider.

In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:

Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

1. In any year, during the period of May 1 through December 15 inclusive, the customers shall receive continuous ("**Firm**") service from EPCOR, except where impacted by events as specified in EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service including force majeure. During the period of December 16 through April 30 inclusive, any authorized overrun service shall be interruptible at the sole discretion of EPCOR. All service during the period December 16 through April 30 inclusive shall be subject to EPCOR's prior authorization under the daily nomination procedures outlined in this Rate Schedule and shall constitute Overrun Gas.

2. To the extent that EPCOR's Upstream Service Provider provides any seasonal or day-to-day balancing rights for EPCOR, the customer shall be entitled to a reasonable proportion of such balancing rights as determined by EPCOR from time to time. If the customer utilizes any of EPCOR's seasonal or day-to-day balancing services or any other services available from the Upstream Service Provider, the customer agrees to comply with all balancing requirements imposed by the Upstream Service Provider. The customer also agrees to be liable for its share of any such usage limitations or restrictions, fees, costs or penalties associated with the usage of such services, including but not limited to any associated storage fees, daily or cumulative balancing fees or penalties, and gas commodity costs as determined by EPCOR, acting reasonably.

3. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards and Load Balancing Arrangement are available at www.uniongas.com.

4. The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE 16 – Contracted Firm Service

Applicability

Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m^3.

Rate

Rates per m^3 assume energy content of 38.89MJ/m^3.

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

Monthly Fixed Charge	$1,500.00	
Delivery Charge		
Per m^3 of Contract Demand	102.3139	¢ per m^3
Upstream Charges		
Upstream Recovery charge per m3 of Contract Demand	14.2815	¢ per m^3
Transportation charge per m3 of Contract Demand		
Transportation from Dawn	18.4282	¢ per m^3
Transportation from Kirkwall	11.7663	¢ per m^3
Transportation from Parkway	11.7663	¢ per m^3
Carbon Charges		
Federal Carbon Charge (if applicable)	3.9100	¢ per m^3

Unaccounted for Gas:

Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:

Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer shall constitute "Overrun Gas" and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	5.0000	¢ per m^3

Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer without EPCOR's approval in advance shall constitute "Unauthorized Overrun Gas". Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges.

Unauthorized Overrun Charge	389.0000	¢ per m^3

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

Nominations:

Union Gas Limited will be the "Upstream Service Provider" to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate and Fuel Ratio. The Forecasted UFG rate is as set out in this Rate Schedule. The Fuel Ratio is the Shipper Supplied Fuel rates applicable to the receipt point of gas defined in the "Gas Supply" section of this Rate Schedule.

The nomination calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Customers may change daily nominations based on the nomination windows within a day as defined by EPCOR's agreement with the Upstream Service Provider.

In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:

Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Gas Supply:

Unless otherwise authorized by EPCOR, customers under this Rate Schedule must deliver firm gas at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). The customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. T-Service Receipt Contract rates are described in Rate Schedule T1.

The customer must deliver to EPCOR on a daily basis the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Transportation charges vary depending on the Ontario Delivery Point at the rates provided in this Rate Schedule. The Forecasted UFG rate is as set out in this Rate Schedule, and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service

1. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards, applicable Fuel Ratio, and Load Balancing Arrangement are available at www.uniongas.com.

2. The provisions in the "EPCOR Natural Gas Limited Partnership General Terms and Conditions for Rate 16 Customers" apply, as contemplated therein, to service under this Rate Schedule.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

RATE T1 – Direct Purchase Contract Rate

Availability

Rate T1 is available to all customers or their agent who enter into a T-Service Receipt Contract for delivery of gas to EPCOR. The availability of this option is subject to EPCOR obtaining a satisfactory agreement or arrangement with EPCOR's Upstream Service Provider for direct purchase volume.

Eligibility

All customers who must, or elect to, purchase gas directly from a supplier other than EPCOR. These customers must enter into a T-Service Receipt Contract with EPCOR either directly or through their agent, for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**").

Rate

All charges in the customer's appropriate Rate Schedule excluding Gas Supply Charge shall apply. Applicable Transportation and Storage charges are determined based on the Ontario Delivery Point.

In addition, administration fees apply to customers who elect to enter into a T-Service Receipt Contract with EPCOR and are detailed in the Direct Purchase Contract with the customer or its agent.

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

Unaccounted for Gas:

Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas supplied:

Forecasted Unaccounted for Gas Percentage	0.00	%

Gas Supply:

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must deliver firm gas at a daily volume acceptable to EPCOR, to an Ontario Delivery Point, and, where applicable, must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

The customer or its agent must deliver to EPCOR on a daily basis, at the Ontario Delivery Point, the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Where the Forecasted UFG rate is as set out in this Rate Schedule and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service

The provisions in the "T-Service Receipt Contract General Terms and Conditions" apply, as contemplated therein, to service under this Rate Schedule.

(b) Confirmed; EPCOR Southern Bruce will be able to separately track costs related to any provincial GHG and carbon pricing programs and other federal GHG or carbon pricing programs (besides the GGPPA) in the Greenhouse Gas Emissions Administration Deferral Account (GGEADA).

(c) In accordance with application EB-2018-0264 dated January 1, 2019 EPCOR Southern Bruce is seeking approval to establish three new deferral and variance accounts associated with this application, specifically, the:

- Greenhouse Gas Emissions Administration Deferral Account ("GGEADA") effective April 1, 2019;
- Federal Carbon Charge – Customer Variance Account ("FCCCVA") effective April 1, 2019;
- Federal Carbon Charge - Facility Variance Account ("FCCFVA") effective April 1, 2019.

EPCOR Southern Bruce' proposed deferral and variance accounts satisfy the tests of causation, materiality and prudence in the following manner:

(i) Causation - the costs associated with the GGPPA were not contemplated in current rates and therefore, these costs are outside of the base upon which rates were derived.

(ii) Materiality – Once the utility is operational in 2020, the first full year of service, the total forecasted cost of compliance (related to customer and facility-related cost and administration costs) with the GGPPA will exceed the materiality threshold of $50,000. EPCOR Southern Bruce believes that the requirement under the program to separately track these costs justify the need to set up a separate deferral account.

(iii) Prudence – EPCOR Southern Bruce' forecasted costs of compliance with the GGPPA are prudent as they are the direct result of legislation that is outside the control of management, with which EPCOR Southern Bruce is obligated to comply.

EPCOR

9.Staff.33

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *Cost Recovery and Bill Presentation- Federal Carbon Charge*

Questions:

(a) How does EPCOR Southern Bruce plan to present the costs related to the Federal Carbon Charge for applicable customers on customers' bills?

(b) How does EPCOR Southern Bruce plan to present the costs related to the Facility Carbon Charge on EPCOR Southern Bruce' company use volumes on customers' bills?

a. Please explain whether this would also include volumes under OBPS?

(c) Please explain whether there are any issues (such as costs, IT concerns) with including the Federal Carbon Charge on customer-related volumes and Federal Carbon Charge on facility-related volumes together as a single line item on customers' bills.

Responses:

(a) EPCOR Southern Bruce proposes the Federal Carbon Charge be separately identified and charged as a new line item on customers' bills for all customer rate classes.

(b) EPCOR Southern Bruce will incur costs of compliance with the GGPPA that are associated with the operation of the distribution system. Once the utility is operational, EPCOR Southern Bruce will seek approval to add the Facility Carbon Charge to the approved delivery charge on customers' bills to recover the GGPPA costs related to company use volumes. EPCOR Southern Bruce proposes to record costs associated with the company use volumes in its variance account (Federal Carbon Charge – Facility Variance Account) and will seek to have such costs disposed of in a future proceeding.

a. No Facility Carbon Charge costs related to OBPS volumes will be included.

(c) EPCOR Southern Bruce does not have any cost issues or IT concerns associated with including the Federal Carbon Charge and Facility Carbon Charge together as a single line item on customers' bills. ENGLP (Aylmer) has tested internally and discussed with the Continental Utility Solutions, Inc. (CUSI) to confirm that there are no technology issues with implementing this on customer's bills.

9.Staff.34

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.4

Preamble: *Cost Recovery and Bill Presentation - Federal Carbon Charge*

Questions:

(a) Does EPCOR Southern Bruce have any customers that could opt-in to the federal government's OBPS program (Part II of the GGPPA)? Please explain.

i. If so, please explain whether this would impact EPCOR Southern Bruce' 2019 customer-related volume.

(b) Does EPCOR Southern Bruce have any customers that qualify under the Output- Based Pricing system? If so, please explain whether EPCOR Southern Bruce has received Exemption Certificates for these customers.

Responses:

(a) EPCOR Southern Bruce has twenty-seven medium Commercial, seven Large Commercial and five Industrial/Large Agricultural customers that could opt-in to the federal government's OBPS program (Part II of the GGPPA) in 2020, the first full year of service.

i. There would be no impact to EPCOR Southern Bruce' 2019 customer-related volume.

(b) EPCOR Southern Bruce has two potential Industrial/Large Agricultural customers that could be mandatory participants under the Output-Based Pricing system. EPCOR Southern Bruce has not received Exemption Certificates from these customers because they are not customers of the EPCOR Southern Bruce system yet.

9.Staff.35

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.5

Preamble: *EPCOR Southern Bruce is proposing a new deferral account, Regulatory Expense Deferral Account ("REDA"). OEB staff notes that the eligibility criteria of causation, materiality and prudence must be met for establishing a new deferral/variance account. Also, given that this is a cost of service application, EPCOR Southern Bruce would already have amounts built into its OM&A for regulatory expenses.*

Questions:

(a) Does EPCOR Southern Bruce's OM&A include regulatory expenses?

(b) If yes to a) please justify the need for this account, given that OM&A is generally not subject to true-up.

(c) OEB expects that EPCOR Southern Bruce should be able to manage the variations in the OM&A costs. Why does EPCOR Southern Bruce deem it appropriate for the ratepayer to pay for these costs in addition to the amounts recovered in the OM&A?

(d) Please discuss how the proposed account meets the eligibility criteria (causation, materiality, prudence) for establishing a new account.

Responses:

(a) EPCOR Southern Bruce's OM&A includes regulatory expenses related to its expected routine applications such Quarterly Rates Adjustment Mechanism (QRAM) applications and annual IR applications, and costs related to expected Reporting and Recordkeeping Requirements (RRR) reporting. Costs related to participating in generic hearings that impact the utility, Enbridge Gas' (Union Gas') proceedings or one-time filings such as a cost of service application have not been included in the OM&A for the rate stability period.

(b) EPCOR Southern Bruce proposes to use this account in the same manner as EPCOR Aylmer currently does for the REDA account established for that utility. EPCOR Southern Bruce will record in the REDA only the regulatory costs it incurs that are associated with participating in generic hearings that impact the utility, and Enbridge Gas' (Union Gas') proceedings. As noted above, the costs related to these types of proceedings are not included in EPCOR Southern Bruce's OM&A.

(c) The proceedings for which EPCOR proposes to record the associated costs in this account are not within the control of EPCOR and cannot be anticipated or the associated costs accurately forecasted. EPCOR's participation in these proceedings is necessary for the provision of natural gas service to its customers and are therefore to the benefit of the ratepayer.

(d) The proposed account meets the eligibility criteria for establishing a new deferral and variance account as follows:

i. Causation: The forecasted expense must be clearly outside of the base upon which rates were derived. As noted above, these costs are not included in the revenue requirement and are therefore outside the base upon which rates were derived.

ii. Materiality: The forecasted amounts must exceed the materiality threshold of $50,000. EPCOR expects these costs to exceed this materiality threshold given that the costs for participating in such proceedings have historically exceeded this threshold for EPCOR’s Aylmer operations.

iii. Prudence: The nature of the costs and forecasted quantum must be reasonably incurred. Given that the utility’s participation in these types proceedings is necessary for the provision of natural gas service to its customers these costs would be reasonably incurred.

9.Staff.36

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.5

Preamble: *EPCOR Southern Bruce has requested a Municipal Tax Variance Account to record any impacts resulting from changes in municipal tax rates or levies, or the introduction of any new municipal tax or levies that occur during the period covered by this application.*

Questions:

(a) Municipal taxes are part of OM&A expenditures. Please explain why EPCOR Southern Bruce requires the Municipal Tax Variance Account and why it cannot be absorbed as part of routine OM&A expenditures considering that the municipalities will be making a contribution equivalent to the property taxes associated with the natural gas system assets during the rate stability period.

(b) Please justify the need for this account on the basis of materiality.

Responses:

(a) EPCOR's has agreements for contributions equivalent to specific portions of the municipal taxes with the three municipalities within which it will provide natural gas service: Kincardine, Arran-Elderslie and Huron-Kinloss. However, these agreements do not include all portions of the municipal taxes such as school taxes, or county taxes. In addition, EPCOR's distribution pipe will pass through other municipalities where EPCOR does not have such agreements and will be required to pay the full amount of the municipal taxes.

Forecasted municipal taxes included in EPCOR's OM&A are the product of forecasted assessment base and forecasted applicable municipal tax rates. In addition to uncertainty of the municipal tax rates over the 10-year rate stability period, the assessment base cannot be accurately forecasted. The assessment base is determined by the governing tax authority, and as EPCOR Southern Bruce is a greenfield utility it does not have the historical information required to accurately forecast how the municipalities will determine the assessment base.

As demonstrated in (b) below the potential changes in municipal taxes are material and therefore cannot absorbed as part of routine OM&A expenditures. Given the uncertainty of the factors impacting municipal taxes (net of associated municipal contributions) over the rate stability period the proposed Municipal Tax Variance Account (MTVA) is required to protect both the utility and the ratepayer in the event that municipal taxes differ from what was included in rates. In its Decision and Order, the Board confirmed that "Both proponents were to use gross revenue requirement excluding any government grants, municipal contributions and Aids to Construction"[1]. As a result, in this application, the 10-

[1] EB-2016-0137/0138/0139 Decision and Order South Bruce Expansion Applications, Section 4.1, Government Grants and Municipal Contributions and Aid to Construction, page 9

year revenue requirement that was approved in the Board's Decision has been reduced by the value of the external funding[2]. This reduction is to the direct benefit of the ratepayer. Therefore, any difference in the timing of EPCOR receiving external funding versus what is currently forecast should be offset against this direct benefit.

A revised Accounting Order for the MTVA reflecting details on the mechanics of the account has been provided in 9.Staff.39 Attachment 1**.**

(b) Based on EPCOR's analysis of various possible scenarios where the net municipal taxes differ from what was forecasted, the annual variance is expected to exceed the $50,000 materiality limit as demonstrated by the two scenarios presented in the tables below. Table 9.Staff.36-1 presents a scenario where there is a 10% increase in the net municipal taxes which could result from changes in the assessment value and/or tax rates. In this scenario, the difference in in net municipal taxes exceeds the materiality threshold starting in 2021. The scenario in Table 9.Staff.36-2 is one where the three municipalities within which EPCOR will provide natural gas service (Kincardine, Arran-Elderslie and Huron-Kinloss) decide to provide EPCOR with additional contributions equivalent to the school taxes. Under this scenario the materiality threshold would be reached in 2019 and the ratepayers would benefit from the additional contribution from the municipalities.

Table 9.Staff.36-1
Property Taxes (Ten Percent Increase Sensitivity)
(Thousands of Dollars)

	Description	A 2019	B 2020	C 2021	D 2022	E 2023	F 2024	G 2025	H 2026	I 2027	J 2028
1	Property Tax Forecasted)	214	377	547	565	582	590	624	626	629	630
2	Property Tax (10% ncrease)	235	415	601	622	640	649	686	689	692	693
3	/ariance	21	38	55	57	58	59	62	63	63	63

Table 9.Staff.36-2
Property Taxes (No School Tax Sensitivity)
(Thousands of Dollars)

	Description	A 2019	B 2020	C 2021	D 2022	E 2023	F 2024	G 2025	H 2026	I 2027	J 2028
1	Property Tax (Base Case)	214	377	547	565	582	590	624	626	629	630
2	Property Tax (No School Tax)	133	180	233	238	243	245	259	259	260	260
3	/ariance	-80	-197	-314	-327	-339	-345	-365	-367	-369	-370

[2] Exhibit 3, Tab 1, Schedule 1, Table 3-5, page 11

9.Staff.37

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.5

Preamble: *EPCOR Southern Bruce has requested an Energy Content Variance Account to record any variations in revenues and costs resulting from differences in the energy content of the actual gas delivered and the assumed energy content. The assumed energy content is 38.89 MJ/M^3.*

Questions:

(a) Please explain why EPCOR Southern Bruce requires an Energy Content Variance Account considering that differences in the energy content would be captured in volumes delivered. Lower energy content would result in higher volumes delivered and vice versa.

(b) Why would variations in energy content not be captured in the Purchased Gas Commodity Variance Account?

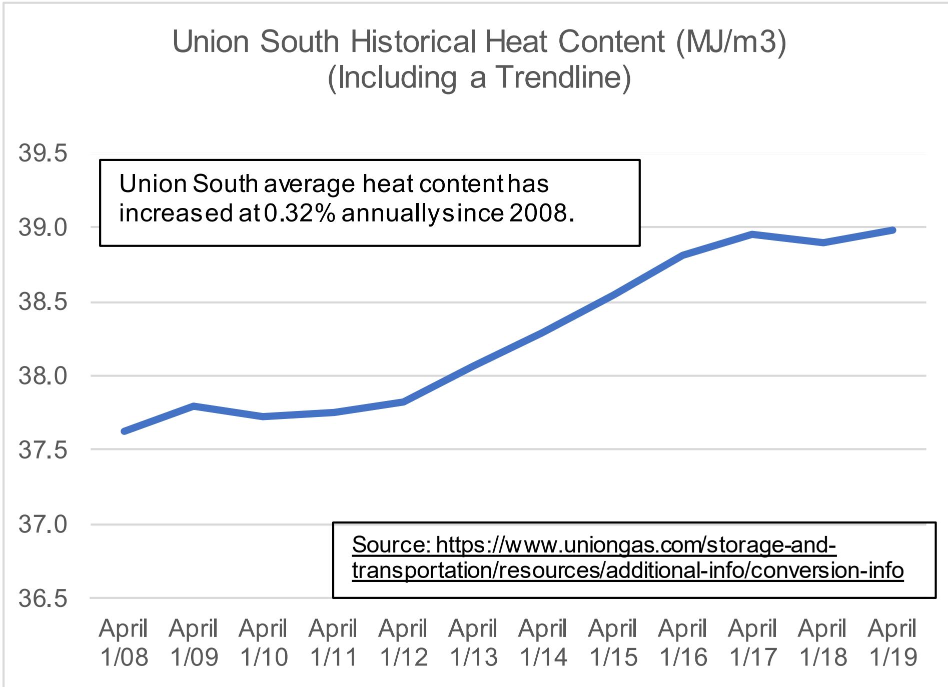
(c) Is EPCOR Southern Bruce aware of other Ontario regulated gas distributors that have an Energy Content Variance Account?

(d) Please provide the mechanics of how this account would operate and explain how change in energy content will be reflected in volumes or costs.

Responses:

(a) Through the CIP process under which EPCOR's revenue requirement and rates were developed, EPCOR accepted the risk of achieving the commitments made related to various components which were within its control including its customer connections and related volume forecast. This volume forecast, on which EPCOR's distribution rates are based, was developed using the noted assumed energy content which is a variable that is not within EPCOR's control.

The heat content for gas in the Union South delivery area has been increasing at the rate of about 0.32% annually since 2008 as illustrated in the graph below:



EPCOR understands that the increase in heat content over the last decade has been the result of a combination of new and traditional supplies arriving at Dawn with higher percentages of natural gas liquids.

As noted above, differences in the energy content of the gas delivered from the assumed energy content would impact the actual volumes delivered thereby impacting the amount of distribution revenue collected from Delivery Charges for all customers in Rates 1, 6 and 11. Rate 16, contract demand customers, are excluded from the calculation of the balances in this account as the revenue from these customers is not impacted by the energy content given that these customers contract for a specified volume.

The Energy Content Variance Account (ECVA) is required to allow for the recovery/refund of any under/over collection of revenue related to Delivery Charges as a result of differences in the volume delivered arising from differences in the energy content of the natural gas. This account will equally protect both the ratepayer and EPCOR from future changes in the heat content of gas over the rate stability period.

(b) As the Purchased Gas Commodity Variance Account (PGCVA) only deals with commodity costs and rates, the impact of the variations in the energy content on distribution revenue as described in (a) above would not be captured in the PGCVA.

(c) EPCOR understands that Enbridge Gas' variance accounts (Average Use True-Up Variance Account in the Enbridge Rate Zone and the Normalized Average Consumption Account in the Union Rate Zones) are global variance accounts that recognize changes in average consumption usage for all reasons, including changes in customer consumption due to increases or decreases in heat content.

(d) On an annual basis the difference between the actual energy content (heat value conversion factor) for the year as provided by the gas provider and the assumed energy content of 38.89 MJ/M3 will be applied to the revenue requirement approved in EB-2016-0137/0138/0139 for Delivery Charges for Rates 1, 6 and 11 for the year as modified by Exhibit 6 of this Application ("CIP Revenue Rates 1, 6 and 11") and this amount will be booked to the ECVA.

In cases where the actual energy content is lower than the assumed energy content this will result in credit booked to the ECVA and actual energy content that is higher than the assumed energy content will result in a debit amount recorded in the ECVA.

The calculation will be as follows:

$$\frac{\text{Actual Energy Content} - 38.89\ \text{MJ/M3}}{\text{Actual Energy Content}} \times \text{CIP Revenue Rates 1, 6 and 11} = \text{Amount to record in ECVA}$$

Debit/Credit Account No. 179.17 Energy Content Variance Account (ECVA)

Credit/Debit Account No. 300 Operating Revenue

A revised Accounting Order for the ECVA reflecting the above details on the mechanics of the account has been provided in 9.Staff.39 Attachment 1.

9.Staff.38

Reference: Exhibit 9 / Tab 1 / Schedule 1 / Pg.6

Preamble: *EPCOR Southern Bruce has requested an External Funding Variance Account to record the difference in timing and quantum of external funding available to the project versus EPCOR's current forecast. The account would record the net present value of the carrying cost (whether positive or negative) in the difference between when EPCOR Southern Bruce has forecast it will receive the funds and when funds are actually received.*

Questions:

Please provide the timelines that EPCOR Southern Bruce has forecasted for receiving the funds.

Responses:

The timing EPCOR has forecasted for receiving the funds is outlined in Exhibit 2 Tab 1 Schedule 1 Table 2-3 Row 4. EPCOR forecasts to receive $8.535 million in 2019 and $13.465 million in 2020.

9.Staff.39

Reference: Exhibit 9 / Tab 2 / Schedule 1 / Pgs.1-17

Preamble: *All Accounting Orders*

Questions:

(a) Please include an effective date for each Accounting Order.

(b) Please indicate in each Accounting Order how and when the balances would be proposed for disposition.

Responses:

(a) The proposed effective date for each Accounting Order is as follows:

	Deferral/variance Account	**A** **Effective Date**
1	Purchased Gas Commodity Variance Account ("PGCVA")	January 1, 2019
2	Gas Purchase Rebalancing Account ("GPRA")	January 1, 2019
3	Storage and Transportation Variance Account Rates 1, 6 & 11 ("S&TVA Rates 1, 6 a& 11)")	January 1, 2019
4	Transportation Variance Account Rate 16 ("TVA Rate 16")	January 1, 2019
5	Unaccounted for Gas Variance Account ("UFGVA")	January 1, 2019
6	Greenhouse Gas Emissions Administration Deferral Account	January 1, 2019
7	Federal Carbon Charge – Customer Variance Account ("FCCCVA")	April 1, 2019
8	Federal Carbon Charge – Facility Deferral/Variance Account ("FCCFVA")	April 1, 2019
9	Regulatory Expense Deferral Account ("REDA")	January 1, 2019
10	Municipal Tax Variance Account ("MTVA")	January 1, 2019
11	Energy Content Variance Account ("ECVA")	January 1, 2019
12	Regulatory Asset Deferral Account ("RADA")	N/A (see below)
13	Contribution in Aid of Construction Variance Account ("CIACVA")	January 1, 2019
14	External Funding Variance Account ("EFVA")	January 1, 2019

Although details of EPCOR's storage and transportation related contracts with its upstream suppliers are still uncertain, EPCOR expects the nature of the upstream charges to be different for the Rate 16 customers than for other customers and therefore proposes to establish two separate variance accounts (the S&TVA Rates 1, 6 and 11 and the TVA Rate 16) as noted in the table above. As well, upon further review, EPCOR believes it is best to handle all variances related to upstream costs including all Transportation and Storage Costs and Upstream Recovery Costs within the same variance account. Accordingly, EPCOR is proposing the S&TVA Rate 1, 6 and 11 and the TVA Rate 16 accounts include variances previously captured by the proposed Regulatory Asset Deferral Account ("RADA") and is no longer requesting the establishment of the RADA.

The revised draft Accounting Orders provided in 9.Staff.39 Attachment 1 reflect the above revisions and have been updated to include the associated proposed effective date.

(b) EPCOR will deal with the balances in the Purchased Gas Commodity Variance Account ("PGCVA") and Gas Purchase Rebalancing Account ("GPRA") through its Quarterly Rate Adjustment Mechanism ("QRAM") applications. All other deferral and variance accounts ("DVA") will be brought forward for disposition as a part of EPCOR's annual IR application unless otherwise directed by the Board as may be the case with the DVA's related to greenhouse gas emissions.

EPCOR has not yet determined the manner which it will propose to dispose of all of the DVA's. If not defined in the draft Accounting Order, the methodology to dispose of each account will be proposed when the balances are brought forward for disposition.

The revised draft Accounting Orders provided in 9.Staff.39 Attachment 1 have been updated to include the timing of when the balances will be proposed for disposition.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

PURCHASED GAS COMMODITY VARIANCE ACCOUNT ("PGCVA")

The Purchased Gas Commodity Variance Account ("PGCVA") is to record the effect of price variances between actual natural gas commodity purchase prices and the forecast prices that underpin EPCOR Southern Bruce's rates charged to customers. Without this variance account, lower than forecast gas purchase prices would result in an over recovery from customers, and higher than forecast gas purchase prices would result in an under recovery by EPCOR. This variance account eliminates exposure to the risk of purchased gas price variances for both customers and EPCOR. The effective date of this account is January 1, 2019.

The actual unit cost of purchased gas is determined by dividing the total commodity costs by the actual volumes purchased in the month. The rate differential between the PGCVA reference price for the period and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGCVA monthly. The PGCVA reference price will be adjusted quarterly as part of the Quarterly Rate Adjustment Mechanism (QRAM) process. The PGCVA reference price will be calculated based on both the forecast gas costs for the forward looking 12-month period and the balance in the PGCVA at the beginning of the 12 month period to factor in the disposition of the PGCVA account balances in the determination of the new PGCVA reference price.

Simple interest is to be calculated monthly on the opening balance in the PGCVA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the monthly difference between actual gas cost and the forecasted gas cost underpinning EPCOR's rates (i.e. reference price) approved by the Board:

   Debit/Credit Account No. 179.27 Purchased Gas Commodity Variance Account ("PGCVA")
   Credit/Debit Account No. 623 Gas Costs

ii. To record simple interest on the opening monthly balance of the PGCVA:

   Debit/Credit Account No. 179.28 Interest on Purchased Gas Commodity Variance Account
   Credit/Debit Account No. 323 Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

GAS PURCHASE REBALANCING ACCOUNT (“GPRA”)

The Gas Purchase Rebalancing Account (“GPRA”) is to record the change in the value of gas inventory available for sale to customers as a result of changes to EPCOR Southern Bruce’s PGCVA reference price as approved by the Board. This variance account ensures that gas inventory available for sale is valued at the current approved commodity price. The effective date of this account is January 1, 2019.

When a new Board-approved reference price comes into effect at the beginning of a quarter, the difference between the new Board-approved reference price and the prior reference price will be applied to the volume of gas in inventory. This adjustment amount will be recorded to value opening inventory volumes at the Board-approved quarterly PGCVA reference price in effect.

The GPRA balance will be disposed of through the GPRA recovery rate included as part of EPCOR’s gas supply charges. The GPRA recovery rate will be adjusted quarterly through the Quarterly Rate Adjustment Mechanism (QRAM) process.

Simple interest is to be calculated monthly on the opening balance in the GPRA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the adjustment necessary to value actual inventory volumes at a rate equal to the PGCVA reference price.

   Debit/Credit Account No. 179.35 Gas Purchase Rebalancing Account (“GPRA”)
   Credit/Debit Account No. 623 Gas Costs or Account No. 152 Gas in Storage

ii. To record simple interest on the opening monthly balance of the GPRA:

   Debit/Credit Account No. 179.36 Interest on Gas Purchase Rebalancing Account
   Credit/Debit Account No. 323 Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

STORAGE AND TRANSPORTATION VARIANCE ACCOUNT FOR RATES 1, 6 & 11 ("S&TVA Rates 1, 6 & 11")

The Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11") is to record the difference between actual total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges (including all Upstream Recovery Charges and Transportation and Storage Charges) recovered from these customers. The S&TVA Rates 1, 6 & 11 records the difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. The effective date of this account is January 1, 2019.

The S&TVA Rates 1, 6 & 11 will record: (a) the variance between the forecast storage and transportation demand levels and the actual storage and transportation demand levels; (b) amounts credited or invoiced from storage and transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative costs for storage and transportation including costs associated with daily nominations, load balancing, and storage procurement.

EPCOR has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity EPCOR was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the S&TVA Rates 1, 6 & 11 account and EPCOR estimates that this balance will reach its maximum in 2024.

EPCOR proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas. When the balance in this account is brought forward for disposition EPCOR will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved interest rate for long term debt. EPCOR is proposing to use the Board approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e remaining life of 30-year upstream transportation contract.

Accounting Entries

i. To record the difference between total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges recovered from these customers:

   Debit/Credit Account No. 179.11 Storage and Transportation Variance Account Rates 1, 6 & 11 (S&TVA Rates 1, 6 & 11)
   Credit/Debit Account No. 624 Gas Supply

ii. To record simple interest on the opening monthly balance of the S&TVA Rates 1, 6 & 11:

   Debit/Credit Account No. 179.12 Interest on Storage and Transportation Variance Account Rates 1, 6 &11
   Credit/Debit Account No. 323 Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

TRANSPORTATION VARIANCE ACCOUNT FOR RATE 16 ("TVA Rate 16")

The Transportation Variance Account for Rate 16 ("TVA Rate 16") is to record the difference between actual total upstream costs, including all Transportation Costs and Upstream Recovery Costs, incurred for all customers in Rate 16 and the Upstream Charges (including all Upstream Recovery Charges and Transportation Charges) recovered from these customers. The TVA Rate 16 records difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. The effective date of this account is January 1, 2019.

The TVA Rate 16 will record, as applicable: (a) the variance between the forecast transportation demand levels and the actual transportation demand levels; (b) amounts credited or invoiced from transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative gas supply costs including costs associated with daily nominations and load balancing.

EPCOR has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity EPCOR was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the TVA Rate 16 account and EPCOR estimates that this balance will reach its maximum in 2024.

EPCOR proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas. When the balance in this account is brought forward for disposition EPCOR will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream

Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved interest rate for long term debt. EPCOR is proposing to use the Board approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e remaining life of 30-year upstream transportation contract.

Accounting Entries

i. To record the difference between total Upstream Costs, including all Transportation Costs and Upstream Recovery Costs, incurred for all customers in Rate 16 and the Upstream Charges recovered from these customers:

   Debit/Credit Account No. 179.19 Transportation Variance Account Rate 16 (TVA Rate 16)
   Credit/Debit Account No. 624 Gas Supply

ii. To record simple interest on the opening monthly balance of the TVA Rate 16:

   Debit/Credit Account No. 179.20 Interest on Transportation Variance Account Rate 16
   Credit/Debit Account No. 323 Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

UNACCOUNTED FOR GAS VARIANCE ACCOUNT (“UFGVA”)

The Unaccounted for Gas Variance Account (“UFGVA”) is to record the cost of gas for EPCOR Southern Bruce that is associated with volumetric variances between the actual volume of Unaccounted for Gas (“UFG”) and the Board approved UFG volumetric forecast included in the determination of rates. The effective date of this account is January 1, 2019.

The gas costs associated with the UFG variance will be calculated at the end of each calendar year based on the estimated volumetric variance between the applicable Board approved level of UFG and the estimate of the actual UFG. The UFG annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGCVA reference price. If required, an adjustment will be made in the subsequent year to record any differences between the estimated UFG and actual UFG. Where there are recoveries of gas loss amounts invoiced as part of third party damages, the gas loss amounts will be removed from the gas cost associated with UFG for the purposes of determining and recording a UFGVA balance.

The audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance in the UFGVA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the costs associated with unaccounted for gas based on the estimated volumetric variance between the actual UAG and the Board approved level:

   Debit/Credit Account No.179.13 Unaccounted for Gas Variance Account (UFGVA)
   Credit/Debit Account No. 623 Cost of Gas

ii. To record the recovery of gas loss amounts invoiced to third parties:

   Debit Account No. 140 Sundry Accounts Receivable

Credit Account No. 179.13 Unaccounted For Gas Variance Account (UFGVA)

iii. To record simple interest on the opening monthly balance of the UFGVA:

Debit/Credit Account No. 179.14 Interest on Unaccounted For Gas Variance Account

Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

GREENHOUSE GAS EMISSIONS ADMINISTRATION DEFERRAL ACCOUNT (“GGEADA”)

The Greenhouse Gas Emissions Administration Deferral Account (“GGEADA”) is to record the administrative costs associated with the impacts of the Greenhouse Gas Pollution Pricing Act (“GGPPA”) for EPCOR’s South Bruce operation. The effective date of this account is January 1, 2019.

Simple interest is to be calculated monthly on the opening balance in the GGEADA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

<u>Accounting Entries</u>

i. To record the administrative costs associated with the impact of the GGPPA:

   Debit/Credit Account No. 179.60 Greenhouse Gas Emissions Administration Deferral Account (GGEADA)

   Credit/Debit Account No. ___. ___ Various accounts

ii. To record simple interest on the opening monthly balance of the GGEADA:

   Debit/Credit Account No. 179.61 Interest on Greenhouse Gas Emissions Administration Deferral Account

   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

FEDERAL CARBON CHARGE – CUSTOMER VARIANCE ACCOUNT (“FCCCVA”)

The Federal Carbon Charge – Customer Variance Account (“FCCCVA”) is to address costs for EPCOR’s Southern Bruce operations arising from the obligations resulting from the Greenhouse Gas Pollution Pricing Act (“GGPPA”) associated with the natural gas that EPCOR delivers to its customers. This account will record the variances between EPCOR’s actual customer related GGPPA costs and customer related GGPPA costs recovered in rates for distribution volumes delivered by EPCOR. The effective date of this account is April 1, 2019.

Simple interest is to be calculated monthly on the opening balance in the FCCCVA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Accounting Entries

i. To record variances between EPCOR’s actual customer related GGPPA costs and customer related GGPPA costs recovered in rates for distribution volumes delivered to customers:

   Debit/Credit Account No. 179.62 Federal Carbon Charge – Customer Variance Account (FCCCVA)
   Credit/Debit Account No. 529 Gas Sales

ii. To record simple interest on the opening monthly balance of the FCCCVA:

   Debit/Credit Account No. 179.63 Interest on Federal Carbon Charge – Customer Variance Account
   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

FEDERAL CARBON CHARGE – FACILITY DEFERRAL/VARIANCE ACCOUNT (“FCCFVA”)

The Federal Carbon Charge – Facility Deferral/Variance Account (“FCCFVA”) is to address costs arising from the obligations resulting from the Greenhouse Gas Pollution Pricing Act (“GGPPA”) associated with EPCOR’s facilities for its Southern Bruce operation. Until such time that EPCOR has received Board approval to include a Federal Carbon Charge – Facility related charge in its rates charged to customers this account will record actual facility associated GGPPA costs incurred by EPCOR Southern Bruce. After EPCOR receives approval to include a Federal Carbon Charge – Facility related charge in its rates, this account will record the differences between actual facility associated GGPPA costs and facility associated GGPPA costs recovered in rates. The effective date of this account is April 1, 2019.

Simple interest is to be calculated monthly on the opening balance in the FCCFVA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Accounting Entries

i. To record EPCOR’s actual facility related GGPPA costs (prior to approval to include a GGPPA facility related charge in rates) or the variances between EPCOR’s actual facility related GGPPA costs and facility related GGPPA costs recovered in rates:

   Debit/Credit Account No. 179.64 Federal Carbon Charge – Facility Deferral/Variance Account (FCCFVA)

   Credit/Debit Account No. 529 Gas Sales

ii. To record simple interest on the opening monthly balance of the FCCFVA:

   Debit/Credit Account No. 179.65 Interest on Federal Carbon Charge – Facility Deferral/Variance Account Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

REGULATORY EXPENSE DEFERRAL ACCOUNT ("REDA")

The Regulatory Expense Deferral Account ("REDA") is to record EPCOR Southern Bruce's costs associated with participating in generic hearings that impact the utility, and Enbridge Gas/Union Gas proceedings. The effective date of this account is January 1, 2019.

Simple interest is to be calculated monthly on the opening balance in the REDA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance in this account, together with carrying charges, will brought forward for approval for disposition on an annual basis. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Accounting Entries

i. To record the cost for participating in generic proceedings and Enbridge/Union Gas proceedings, including a main rates case:

   Debit/Credit Account No. 179.21 Regulatory Expense Deferral Account (REDA)

   Credit/Debit Account No.___. ___ Various accounts

ii. To record simple interest on the opening monthly balance of the REDA:

   Debit/Credit Account No.179.22 Interest on Regulatory Expense Deferral Account

   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

MUNICIPAL TAX VARIANCE ACCOUNT (“MTVA”)

The Municipal Tax Variance Account (”MTVA”) is to record the difference between the actual annual municipal taxes paid, net of municipal contributions related to municipal taxes, and the net municipal taxes included in the annual revenue requirement for EPCOR’s Southern Bruce operations as approved in EB-2018-0264 for each year of the rate stability period. The effective date of this account is January 1, 2019.

The audited balance in this account, together with carrying charges, will brought forward for approval for disposition on an annual basis. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance of this account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>Accounting Entries</u>

i. To record the difference between actual annual net municipal taxes paid and net municipal taxes included in the annual approved revenue requirement:

   Debit/Credit Account No. 179.15 Municipal Tax Variance Account (”MTVA”)

   Credit/Debit Account No. 305 Municipal Tax

ii. To record simple interest on the opening monthly balance of the MTVA:

   Debit/Credit Account No.179.16 Interest on Municipal Tax Variance Account

   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

ENERGY CONTENT VARIANCE ACCOUNT ("ECVA")

The Energy Content Variance Account ("ECVA") is to record differences in variable revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M3 used in determining EPCOR Southern Bruce's revenue requirement and delivery rates as approved in EB-2018-0264. Differences in the energy content of the gas delivered from the assumed energy content would impact the actual volumes delivered thereby impacting the amount of revenue collected over EPCOR's 10-year rate stability period. The effective date of this account is January 1, 2019.

This account will capture the impact of energy content changes on variable revenue by applying the energy content change to the revenue earned from Delivery Charges for all customers in Rates 1, 6 and 11. Rate 16, contract demand customers, are excluded from the calculation of the balances in this account as the revenue from these customers is not impacted by the energy content given that these customers contract for a specified volume.

On an annual basis the amount to be recorded in this account will be calculated by taking the difference between the actual energy content (heat value conversion factor) for the year as provided by the gas provider and the assumed energy content of 38.89 MJ/M3 and applying this to the revenue approved in EB-2016-0137/0138/0139 for Delivery Charges for Rates 1, 6 and 11 for the year as modified by EB-2018-0264 ("CIP Revenue Rates 1, 6 and 11"). The calculation will be as follows:

$$\frac{\text{Actual Energy Content} - 38.89\ \text{MJ/M3}}{\text{Actual Energy Content}} \times \text{CIP Revenue Rates 1, 6 and 11} = \text{Amount to record in ECVA}$$

In cases where the actual energy content is lower than the assumed energy content this will result in credit booked to the ECVA and actual energy content that is higher than the assumed energy content will result in a debit amount recorded in the ECVA.

The audited balance in this account, together with carrying charges, will brought forward for approval for disposition on an annual basis. The balance in this account will be apportioned to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class. Other details on the manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance in the ECVA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the difference in revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M3:

   Debit/Credit Account No. 179.17 Energy Content Variance Account (ECVA)

   Credit/Debit Account No. 300 Operating Revenue

ii. To record simple interest on the opening monthly balance of the ECVA :

   Debit/Credit Account No.179.18 Interest on Energy Content Variance Account

   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

Contribution in Aid of Construction Variance Account ("CIACVA")

The Contribution in Aid of Construction Variance Account ("CIACVA") is to record the revenue requirement impact of any differences between the actual capital contributions that EPCOR Southern Bruce pays to Enbridge Gas/Union Gas related to Enbridge's Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the capital contribution included for these projects for the purposes of determining EPCOR's approved rates. Enbridge Gas provided EPCOR with a forecasted contribution value of $2.363 million for the Owen Sound Transmission Reinforcement and $2.935 million for the Dornoch Meter and Regulator Station. These values have been included in EPCOR's capital budget and form part of the utility's rate base. The costs associated with this capital are recovered through the Upstream Recovery Charge included in the proposed rates and changes to the contribution values will have a direct impact on the amount of capital EPCOR proposes to recover through the Upstream Recovery Charge. The effective date of this account is January 1, 2019.

The balance of this account would be calculated as the revenue requirement impact resulting from the difference between the forecasted capital contribution values provided by Enbridge Gas/Union Gas and the actual capital contributions paid. No balance will be recorded in this account until such time as the actual capital contribution amounts EPCOR is required to pay to Enbridge Gas/Union Gas are finalized. Once the actual capital contributions are finalized the cumulative revenue requirement impact to date will be calculated and recorded in this account, after which the balance will be recorded annually. In its cost of service application for rates commencing 2029 EPCOR will propose to adjust its rate base to record the depreciated difference in capital contribution so as to appropriately reflect the finalized capital contribution paid in its rate base and revenue requirement commencing 2029.

The balance in this account, together with carrying charges, will brought forward for disposition on an annual basis at which time EPCOR will propose a methodology and timing for disposition of the balance that aligns with customers' use of the capacity and EPCOR's rate smoothing objectives

Simple interest is to be calculated monthly on the opening balance in this account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the revenue requirement impact resulting from the difference between the forecasted capital contribution values provided by Enbridge Gas/Union Gas and the actual capital contributions paid:

   Debit/Credit Account No. 179.74 Contribution in Aid of Construction Variance Account (CIACVA)
   Credit/Debit Account No. 300 Operating Revenue

ii. To record simple interest on the opening monthly balance of the CIACVA :

   Debit/Credit Account No.179.75 Interest on Contribution in Aid of Construction Variance Account
   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP

ACCOUNTING ORDER

External Funding Variance Account ("EFVA")

The External Funding Variance Account ("EFVA") is to record the impact of the difference in timing and quantum of external funding available to the project versus EPCOR's forecast as reflected in approved rates. EPCOR is expecting $22.0 million in funding as detailed in Schedule 1 of the Ontario Regulation 24/19 Expansion of Natural Gas Distribution Systems. It is expected that EPCOR will receive this funding starting in December, 2019 and a payment will be made in each subsequent quarter until December 2020. However, the final timing as to when EPCOR will receive this funding, as well as the quantum of each payment, has not been confirmed. This account would record the net present value of the carrying cost (whether positive or negative) in the difference between EPCOR's forecast and when funds are actually received. The effective date of this account is January 1, 2019.

The balance in this account, together with carrying charges, will brought forward for disposition as part of the annual IR application following receipt of the final payment.

Simple interest is to be calculated monthly on the opening balance in this account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the impact of the difference in timing and quantum of external funding available to the project versus EPCOR's forecast as reflected in approved rates:

   Debit/Credit Account No. 179.76 External Funding Variance Account (EFVA)

   Credit/Debit Account No. ___. ___ Various accounts

ii. To record simple interest on the opening monthly balance of the EFVA:

   Debit/Credit Account No.179.77 Interest on External Funding Variance Account

   Credit/Debit Account No. 323 Other Interest Expense

10.Staff.40

Reference: Exhibit 10 / Tab 1 / Schedule 1 / Pg.1

Preamble: *EPCOR Southern Bruce has proposed an Incentive Rate-setting Plan (Custom IR Plan) to set rates for the 10-year rate stability period commencing January 1, 2019 through December 1, 2028.*

Questions:

(a) Please explain why EPCOR Southern Bruce has not included an earnings dead band off-ramp mechanism as part of its Custom IR Plan.

(b) Will EPCOR Southern Bruce report its earnings during the Custom IR period?

(c) Please explain how ratepayers will be protected if there is no earnings sharing or off-ramp?

Responses:

(a) EPCOR has not included an earnings dead band off-ramp mechanism as part of its Custom IR Plan because prospective ratepayers in Southern Bruce have already been afforded protection against overpaying through the Board's competitive process to select a gas distributor for the region. EPCOR's cumulative 10-year revenue requirement per unit of volume submitted to the Board was arrived at via EPCOR incorporating cost control and built-in incentives in order to maintain the most favourable cost structure. In addition, the Board determined in the competitive process that return on equity was a competitive component: "However, the cost of debt and return on equity (ROE) were considered competitive"[1]. That combined with the fact that the utility has accepted a symmetrical risk regarding its return on equity does not align with having an earnings dead band off-ramp.

An objective of the competitive process was to enable expansion of natural gas distribution into regions that have been previously unserved while ensuring that rate payers are charged rates that reflect the best value: "The primary benefit of the introduction of competition identified in the generic decision is the discipline it instills to control costs and the search for efficiencies in system expansion and operation."[2] In other words, the competitive tension inherent in the OEB's process has allowed the OEB to

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[1] EB-2016-0137/0138/0139, Decision and Order South Bruce Expansion Applications, April 12, 2018, Section 4.1, Capital Structure, page 9

[2] EB-2016-0137/0138/0139, Partial Decision on the Issues List and Procedural Order No.6, June 27, 2017, Partial Decision on Issues, page 3

benchmark proposed costs resulting in the lowest rate to new customers while avoiding cross subsidization by current customers.

In addition to ensuring that ratepayers are receiving value, the OEB also introduced a 10-year rate stability period. A driver of the stability period was to shift risk that is typically born by the ratepayer to the utility. EPCOR bears the risk during the 10-year period of both: (a) fewer customer attachments than forecasted or higher OM&A costs; and (b) capital cost overruns. With respect to (a), this risk is different than that typically borne by a utility: “At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected.”[3] The same is true with respect to (b): “Any capital cost overruns incurred during the first 10 years above the forecasted costs reflected in the proposals will not be permitted into the successful proponent’s rate base for year 11 and beyond (following the rate stability period).”[4]

In summary, in its Generic Decision the OEB recognized that it was creating a win-win scenario where to be successful a proponent of a system expansion must exercise discipline to control costs and search for efficiencies while also being incented to keep its rates low as this could lead to increased returns for that utility during the 10-year rate stability period: “The selected proponent would then be incented to maintain low rates in order to be attractive to potential customers which would in turn increase its margins.”[5]

(b) As detailed in Exhibit 1.7 Performance Measurement and Scorecard, EPCOR is proposing to report its earnings during the Custom IR period.

(c) In addition to EPCOR’s response to (a) above, as potential customers are presently receiving their energy from other suppliers, they can compare their current cost to that offered by EPCOR and make an informed decision about whether to convert to natural gas and take service from EPCOR. If they do choose to convert, ratepayers will then be protected during the 10-year rate stability period as they are assured of stable rates during that period. For periods beyond 10 years, EPCOR will be regulated under a typical cost of service framework that would generally incorporate an earnings sharing or off-ramp.

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[3] EB-2016-0004, Decision With Reasons, Ontario Energy Board Generic Proceeding on Community Expansion, November 17, 2016, Section 6 OEB Findings page 20
[4] EB-2016-0137/0138/0139, Decision and Order, South Bruce Applications, April 12, 2018, Section 4.1 Proponent Selection Criteria Determinations in South Bruce Expansion Applications, Treatment of Capital Costs, page 10
[5] EB-2016-0004, Decision With Reasons, Ontario Energy Board Generic Proceeding on Community Expansions, November 17, 2016, Section 6 OEB Findings, page 20

10.Staff.41

Reference: Exhibit 10 / Tab 1 / Schedule 1 / Pg.2

Preamble: *EPCOR Southern Bruce has proposed that the annual incentive rate adjustment include a factor to adjust the forecast inflation factor applied to the OM&A portion of the monthly fixed charge and delivery charge of each rate schedule to reflect actual inflation. In addition, the stabilization factor of 1.27% will be applied against the remaining portion of distribution charges. For ease of calculation, EPCOR Southern Bruce has proposed that in each year's incentive rate adjustment, inflation will be applied against 31.6% of that year's distribution charges for each rate class.*

Questions:

(a) Please provide the reference in the EB-2016-0137/38/39 Decision and Order where the OEB has indicated that EPCOR Southern Bruce can apply the 1.27% inflation rate to escalate rates every year during the rate stability period.

(b) Please provide the supporting calculations for the derivation of the proposal wherein EPCOR Southern Bruce intends to apply inflation against 31.6% of the distribution charges and 1.27% to the remaining portion.

Responses:

(a) The OEB determined the methodology for determining the inflation rate to be applied in "… which should be equivalent to the estimated long term inflation rate based on the most recent four quarter average GDP IPI FDD methodology accepted by the OEB."[1] The calculation resulting in the 1.27% is as follows.

$$Inflation\ Rate = \frac{[\%\Delta GDP\ IPI\ FDD_{Q3\ 2016} + \%\Delta GDP\ IPI\ FDD_{Q4\ 2016} + \%\Delta GDP\ IPI\ FDD_{Q1\ 2017} + \%\Delta GDP\ IPI\ FDD_{Q2\ 2017}}{4}$$

$$Inflation\ Rate = \frac{0.95\% + 1.21\% + 1.29\% + 1.63\%}{4}$$

$$Inflation\ Rate = 1.27\%$$

Where **%ΔGDP IPI FDD** is the percentage change in year over year GDP IPI FDD index published by Statistics Canada

[1] EB-2016-0137/0138/0139, Decision on Preliminary Issues and Procedural Order No. 8, August 22, 2017, Inflation Costs, page 8

(b) The revised OM&A relative percentage of the distribution revenue should be 31.4%. It is derived as per below:

<u>O&M Relative to Distribution Revenue</u>

	Col. 1 Capital Component	Col. 2 Calculation	Col. 3 Value
Row 1	10 Year Cumulative O&M		18,360[2]
Row 2	10 Year Cumulative Distribution Revenue		58,535[3]
Row 3	O&M Relative Percentage	R1 / R2	31.4%

[2] Exhibit 4 Tab 1 Schedule 2 Table "Operating Expense"
[3] Exhibit 8 Tab 1 Schedule 4 Table "Ten Year Revenue Forecast"

10.Staff.42

Reference: Exhibit 10 / Tab 1 / Schedule 1 / Pg.3

Preamble: *EPCOR Southern Bruce has indicated that it has already applied productivity and stretch factors in its proposed 10-year revenue requirement. Driven by the competitive tension inherent within the OEB's process, the productivity and stretch factors were by necessity incorporated into its CIP revenue requirement in order to become the successful proponent. It is the view of EPCOR Southern Bruce that the competitive process has already resulted in a revenue requirement that incorporates productivity and stretch factors, and to apply additional factors would result in doubling up on these elements.*

Questions:

Please confirm that according to EPCOR Southern Bruce there are no more efficiency gains possible as compared to what was proposed in the initial CIP.

Responses:

The ultimate purpose of a productivity factor and stretch factor (i.e., an X factor) is to incent a utility to seek out and achieve efficiency gains, and share those with its customers. The Board's competitive CIP process for the right to develop the Southern Bruce Project was based on putting forward a competitive 10-year revenue requirement. In other words, the process was designed to ensure that that the two bidding utilities made their proposals as efficient as possible during the 10-year term. These efficiencies will be passed on to ratepayers via a lower revenue requirement than would have been the case in the absence of a competitive process.

In addition, the Board's concept of a productivity factor and stretch factor seems ill-suited to a stand-alone utility that has yet to be built. The Board's productivity factor reflects the productivity gains expected in the regulated industry as a whole (e.g., Ontario electricity LDCs), based on objective data. The stretch factor allows for variance at the level of the individual utility, based on that utility's current efficiency level at the start of any IR plan term. The ten-year period covered by this rate application will see EPCOR Southern Bruce move from a utility that has no assets or customers to a built-out system. They are not an existing utility, capable of seeking process improvements, for example, to drive cost savings. Given these unique circumstances, it seems difficult to attribute EPCOR with any "industry-wide" or "utility-specific" expectations.

10.Staff.43

Reference: Exhibit 10 / Tab 1 / Schedule 1 / Pg.6

Preamble: *EPCOR Southern Bruce has requested for availability of an Incremental Capital Module (ICM) as part of its Custom IR Plan.*

Questions:

Please explain how EPCOR Southern Bruce intends to calculate the ICM materiality threshold during the rate stability period. Please provide an example that explains the proposed approach.

Responses:

The values that EPCOR proposes to use to determine the ICM materiality threshold during the rate stability period are as follows.

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

RB = Rate Base forecast for 2028. The rate base used is typically the test year value. Use of forecast rate base in 2028 is consistent with the "test year" proposed in the cost allocation study in the application. This reflects the year where the growth in customer attachments, distribution system infrastructure and operations are most representative of a mature utility. The year 2028 also aligns with the Board's discussion in EB-2014-0219, "… the Board approved ICM funding for both applications noting that the projects were … <u>expenditures that were clearly outside of the base upon which rates were derived</u>."[1] Emphasis added. EPCOR notes that the rates proposed in the application are based on the ultimate rate base which is achieved in 2028.

d = depreciation forecast for the year 2028.

g = growth value is proposed to be 0. The intent of a growth factor is to ensure that "the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping"."[2] This aligns with an ICM threshold value that uses as a starting point the typical "test year" revenue requirement. Such test year revenue takes into account only a single year's revenue requirement and the number of customers forecast for that year. The rates for

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[1] EB-2014-0219, Report of the Board, New Policy Options for the Funding of Capital Investments: The advanced Capital Module, September 18, 2014, Section 2.1, page 6

[2] EB-2007-0673, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Section 2.3, page 32

subsequent years are then increased by the IRM value which implicitly adjusts for inflation and any additional revenue that results from customer growth. EPCOR notes that the 10-year revenue requirement incorporated into this application already explicitly includes both annual price adjustments and forecast customer growth for that period. In forecasting a revenue requirement in its CIP EPCOR adhered to the OEB's direction "The OEB expects the proponents to provide their gross revenue requirement, including inflation as noted above, in their proposals." [3] The rates which support the 10-year revenue requirement in this application also include the growth in customers that EPCOR included in its CIP "The successful proponent will be held to their forecast [growth in customer attachments] for rate-making purposes" [4] [wording in brackets added for clarification]. Therefore to include a second adjustment for growth in the threshold value calculation would result in "double-counting" for growth and inflation and unfairly penalize the utility.

PCI = forecast value of 1.27%. As per the annual adjustment mechanism proposed in Exhibit 10 this would be adjusted annually by applying the OEB's Input Price Methodology.

N = 1. The intent of the N value (number of years after rebasing) is to annualize the growth factor. As per above, including a growth factor would result in double counting for customer growth and inflation and therefore penalize the utility.

X = 10%[5] dead band. Value currently directed by the OEB.

An example calculation using the proposed values is as follows:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{\$54{,}946}{\$1{,}934}\right) \times \left(0.0 + 0.0127 \times (1 + 0.0)\right)\right]\right) \times \left((1 + 0.0) \times (1 + .0127)\right)^{1-1} + 0.10$$

Threshold Value = 1.46 or 146%

Materiality threshold = 1.46 x $1.934 million = $2.824 million

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[3] EB-2016-0137/0138/0139, Decision on Preliminary Issues and Procedural Order No. 8, Decision on CIP Parameters, Customer Attachments, page 8
[4] Ibid, page 5
[5] Eb-2014-0219, Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016, Section 4.3, page 18

10.Staff.44

Reference: Exhibit 10 / Tab 1 / Schedule 1 / Pg.7

Preamble: *EPCOR Southern Bruce has proposed to include an adjustment for tax changes in its Custom IR Plan. EPCOR Southern Bruce has proposed a 50/50 sharing of the impacts of legislated tax changes that have not been included in rates.*

Questions:

Please explain why EPCOR Southern Bruce has not requested a deferral and variance account to track any changes in tax legislation.

Responses:

EPCOR Southern Bruce has not requested a deferral and variance account to track the shared impacts of legislated tax changes as it proposes to handle these amounts in the same manner as its Aylmer operation has done historically and for 2020-2024 per the settlement proposal dated June 10, 2019 in proceeding EB-2018-0336.

EPCOR Aylmer (and formerly Natural Resources Gas Limited) does not have a deferral or variance account established for such changes and instead, when applicable, calculates the proposed amount to be shared and the associated 12-month monthly fixed rate riders as part of the annual IR application.

Enbridge 1

Reference: EPCOR Application, Exhibit 1, Tab 2, Schedule 1, pages 14-15

Preamble: *"There are a number of items that were not included in the total gross revenue requirement and as a result the revenue requirement included in the Board's Southern Bruce Expansion Decision is subject to certain adjustments. These include:*

i. Government Grants and Municipal Contributions and Aid to Construction;
ii. Demand-Side Management (DSM) Costs;
iii. Cap and Trade Costs;
iv. Tax holidays from the municipality;
v. Gas Commodity Costs;
vi. Upstream Reinforcement Costs; and
vii. Royalty payments if not recovered through revenue requirement."

Questions:

(a) Please provide additional detail on the municipal contributions that EPCOR is receiving. Please provide copies of any agreements that have been established related to these contributions.

(b) Please provide additional detail on the proposed royalty payments to municipalities. Please provide copies of any agreements that have been established related to these royalty payments.

Responses:

(a) Please see Exhibit 1.5.1 Table 1-4, row 3 that details the forecast annual value of the tax holidays EPCOR expects to receive from the Southern Bruce municipalities. Please see Exhibit 3.2.3 paragraph 6 that provides an explanation regarding the property tax holidays. Also Table 3.5 Row 5 details the expected cumulative value and impact on revenue requirement of these tax holidays.

Please see Exhibit 3, Tab 2, Schedule 1, pages 1 – 6 for copies of the bylaws passed by the Southern Bruce municipalities authorising the tax holidays.

(b) EPCOR is not proposing to make any royalty payments to the municipalities.

Enbridge 2

Reference: Exhibit 1, Tab 2, Schedule 1, pages 19-20

Preamble: *"As the Southern Bruce system is a greenfield project that will be servicing residents who currently receive their energy from other suppliers, all system customers will be new and the impact on individual customers will be a function of the specifics of their existing arrangements. Table 1-3 details the forecast annual bill for the average customer connecting to the system."*

Reference: EPCOR Application, Exhibit 1, Tab 2, Schedule 1, page 44

Preamble: *"Following are examples of the average annual bill for customers in the four rate classes as proposed in this Application. The bill examples are for 2020, the first year that all classes of customers are expected to receive service."*

Questions:

(a) Please confirm that the forecast annual bill in Table 1-3 reflects only distribution-related costs.

(b) Please provide a schedule similar to Table 1-3 showing total annual bills for customers that includes all charges that will be applied (including the proposed revenue deficiency rate rider, the Federal Carbon Tax and any other applicable charges such as LEAP funding and HST) and provide a breakdown of all bill components.

Responses:

(a) Confirmed

(b)

	Customer Type	Rate Class	Distribution Charge ($ / year)[1]	Upstream Recovery Charge ($ / year)	Transportation Charge ($ / year)	Gas Supply Charge ($ / year)	Federal Carbon Tax ($ / year)	HST ($ / year)	Total Bill ($ / year)
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Row 1	Existing Residential	Rate 1 - General Firm Service	880.81	31.76	58.88	271.70	126.15	178.01	1,547.31
Row 2	New Residential	Rate 1 - General Firm Service	858.69	30.53	56.60	261.21	121.27	172.68	1,500.99
Row 3	Small Commercial	Rate 1 - General Firm Service	1,550.57	69.36	128.58	593.35	275.48	340.25	2,957.58
Row 4	Small Agricultural	Rate 1 - General Firm Service	1,557.62	69.76	129.32	596.76	277.06	341.97	2,972.48
Row 5	Medium Commercial	Rate 6 - Large Volume General Firm Service	7,553.53	788.56	1,542.79	3,405.21	1,580.97	1,933.24	16,804.29
Row 6	Large Commercial	Rate 6 - Large Volume General Firm Service	18,323.19	2,215.94	4,335.43	9,569.05	4,442.71	5,055.22	43,941.54
Row 7	Sample Dryer 1	Rate 11 - Large Volume Seasonal Service	17,435.49	35.84	1,872.26	12,832.84	5,958.02	4,957.48	43,091.93
Row 8	Sample Dryer 2	Rate 11 - Large Volume Seasonal Service	54,261.95	119.47	6,240.86	42,776.12	19,860.07	16,023.60	139,282.07

[1] LEAP funding cost is recovered as part of the distribution charge

Enbridge 3

Reference: Exhibit 1, Tab 2, Schedule 1, page 21

Preamble: *"EPCOR is requesting that the Board make its Rate Order effective January 1, 2019. In the event that the OEB is not able to provide a Decision and Rate Order in time for EPCOR to implement its rates effective November 1, 2019 (the approximate timeline at which EPCOR expects to start connecting customers), EPCOR requests that the OEB declare the applied for rates interim effective January 1, 2019 and approve rate riders to recover any change between applied for and approved revenue between the implementation date of the OEB's 2019 Rate Order and November 1, 2019."*

Questions:

Please explain why EPCOR requires a rate order effective January 1, 2019 if it does not expect to connect customers prior to November 2019.

Responses:

In its competitive process the OEB established a 10-year rate stability period that was incorporated into the proponents' CIPs. The financials, including the revenue requirement, of the CIP reflected the impact of that rate stability period. In EPCOR's CIP the 10-year rate stability period started January 1, 2019 with customers connected 4th Quarter of 2019. In determining that EPCOR was the successful proponent, the OEB acknowledged the schedules that were incorporated into the proposal.

Enbridge 4

Reference: Exhibit 1, Tab 2, Schedule 1, page 22

Preamble: *"EPCOR will operate separate business units, one each for the former Natural Resource Gas Limited gas distribution system operated by EPCOR in the Aylmer region and the gas distribution system in the Southern Bruce area. These two gas distribution systems will operate under separate rate schedules and tariffs while sharing certain management and functions so as to increase the efficiencies. Any sharing of management and functions will be governed by a Service Level Agreement ("SLA")."*

Questions:

Please provide a copy of the referenced Service Level Agreement.

Responses:

These services will be governed by the principles outlined in the SLA template provided in Exhibit 4, Tab 2, Schedule 1; however, a SLA will not be executed for the sharing of resources between these two utilities as the Aylmer and Southern Bruce utilities both reside under the same legal entity (EPCOR Natural Gas Limited Partnership).

Enbridge 5

Reference: Exhibit 1, Tab 2, Schedule 1, page 29

Preamble: *"The Southern Bruce system is a greenfield project with construction scheduled to begin in June 2019 and a targeted substantial completion date of October 31, 2021."*

Reference: Exhibit 6, Tab 1, Schedule 1, page 3

Preamble: *"Exhibit 6, Tab 1, Schedule 3 contains the construction schedule as included in EPCOR's CIP as well as the most recent revised construction schedule. The revised construction schedule includes prudent mitigation measures to address the impact of the change from the common parameters to one that reflects the expected timing of receipt of a decision on the LTC. Mitigation measures include ordering long lead time steel pipe necessary to support a compressed 2019 construction season and expanding construction effort including working into December 2019. Without these mitigation measures EPCOR would not be able to begin construction and connect customers at the Bruce Energy Center in 2019.*

The change in timeline for OEB decision on the construction schedule, after the reasonable mitigation steps taken by EPCOR, has triggered a revenue deficiency of $1.764 million on NPV basis compared to that included in EPCOR's CIP. This includes $1.640 million in distribution revenue and $0.124 million in upstream charges."

Reference: Exhibit 6, Tab 1, Schedule 1, page 8

Preamble: *"EPCOR is proposing that the change in distribution revenue requirement adjustment due, distribution revenue deficiency of $1.640 million ($2.324 – $0.224 – $0.460), and deferred recovery of upstream charges of $0.124 million, totaling $1.764 million be recovered through a rate rider applied on a volumetric basis over the 10-year rate stability period."*

Questions:

Please explain why the delays in the construction and customer attachment schedules results in the need to recover additional revenues through a rate rider versus base rates.

Responses:

EPCOR is proposing to recover additional revenues required as a result of delays in construction and customer attachment through a rate rider versus base rates as it allows EPCOR to clearly separate the impact of delays based on common assumptions versus what was committed to in its CIP. This enables the Board to confirm in a straightforward manner that EPCOR is meeting the commitments it made in its CIP.

Enbridge 6

Reference: Exhibit 1, Tab 2, Schedule 1, page 32

Preamble: *"Customer growth over the 10-year rate stability period is as included in EPCOR's CIP and recreated in Table 1-5 below.*

Reference: Exhibit 6, Tab 1, Schedule 1, page 5

Preamble: *"Table 6-4 details the number of customers that EPCOR is projecting it will connect under the revised construction schedule. In an effort to further mitigate the impact of the delay, EPCOR is accepting a more aggressive connection rate than detailed in the CIP (connecting 2,384 customers in 2021 versus 1,093 in the CIP). As a result EPCOR is projecting that it will catch up to CIP values in customer connections by the end of 2021."*

Questions:

Please provide an updated version of Table 6-4 in a format and detail similar to Table 1-5.

Responses:

Table Enbridge 6-1
Updated Customer Connections

	Col. 1 Rate Class	Col. 2 2019	Col. 3 2020	Col. 4 2021	Col. 5 2022	Col. 6 2023	Col. 7 2024	Col. 8 2025	Col. 9 2026	Col. 10 2027	Col. 11 2028
Row 1	Rate 1 - General Firm Service		1,272	3,611	4,246	4,792	5,038	5,094	5,134	5,172	5,179
Row 2	Rate 6 - Large Volume General Firm Service		17	59	79	88	92	92	92	92	92
Row 3	Rate 11 - Large Volume Seasonal Service		1	4	5	5	5	5	5	5	5
Row 4	Rate 16 - Contracted Firm Service	2	2	2	2	2	2	2	2	2	2
Row 5	Sum	2	1,292	3,676	4,332	4,887	5,137	5,193	5,233	5,271	5,278

Enbridge 7

Reference: Exhibit 1, Tab 2, Schedule 1, page 36

Preamble: *"The primary driver of capital expenditures during the 10-year rate stability period is the construction of the greenfield Southern Bruce distribution system as included in EPCOR's CIP and further detailed in its leave to construct application (EB-2018-0263). During the initial years of the rate stability period EPCOR does not expect to incur material maintenance capital. Table 1-8 details the proposed capital expenditures by year during the rate stability period."*

Reference: Exhibit 2, Tab 1, Schedule 1, page 2

Preamble: *"The summarized continuity schedule of all fixed asset is provided in Table 2-2."*

Reference: Exhibit 2, Tab 1, Schedule 1, page 3

Preamble: *"The summarized continuity schedule of the external funded fixed assets is provided in Table 2-3." "The continuity schedule of fixed assets net of the externally funded assets is provided in Table 2-4."*

Questions:

(a) Please provide an updated Table 1-8 based on the revised construction and customer attachments schedules.

(b) Please provide updates for Table 2-2, Table 2-3 and Table 2-4 based on the revised construction and customer attachments schedules.

Responses:

(a)

Table Enbridge 7-1

Updated Summary of Capital Budget

(Thousands of Dollars)

	Asset Group	Col. 1 2019	Col. 2 2020	Col. 3 2021	Col. 4 2022	Col. 5 2023	Col. 6 2024	Col. 7 2025	Col. 8 2026	Col. 9 2027	Col. 10 2028
Row 1	CIAC to Enbridge - Owen Sound Reinforcement	2,363	0	0	0	0	0	0	0	0	0
Row 2	CIAC to Enbridge - Station	2,935	0	0	0	0	0	0	0	0	0
Row 3	Distribution Mains - Metallic	31,471	6,802	0	0	0	0	0	0	0	0
Row 4	Distribution Land Rights	9	27	18	0	0	0	0	0	0	0
Row 5	Distribution Mains - Plastic	0	12,663	18,843	126	130	147	194	162	160	93
Row 6	Distribution Services Plastic	0	4,793	2,025	1,248	1,085	543	164	137	135	78
Row 7	Distribution Meters	0	1,521	647	416	361	181	55	46	45	26
Row 8	Distribution Measuring and Regulating Equipt.	660	529	1,036	0	0	0	0	0	0	0
Row 9	Vehicles	468	0	0	0	0	0	0	0	499	0
Row 10	Machinery and Equipment	0	0	327	0	0	0	0	0	0	0
Row 11	Sum	37,906	26,335	22,897	1,791	1,576	872	413	344	838	197

(b)

Table Enbridge 7-2

Updated Projected Fixed Assets Including External Funded Fixed Assets

(Thousands of Dollars)

	Description	Col. 1 2019	Col. 2 2020	Col. 3 2021	Col. 4 2022	Col. 5 2023	Col. 6 2024	Col. 7 2025	Col. 8 2026	Col. 9 2027	Col. 10 2028
Row 1											
Row 2	**Gross Fixed Assets**										
Row 3	Opening Balance	0	38,374	65,103	88,342	90,159	91,759	92,643	93,062	93,411	94,262
Row 4	Capital Expenditure	37,760	26,187	22,747	1,639	1,422	716	255	185	677	33
Row 5	Interest During Construction	468	394	342	27	24	13	6	5	13	3
Row 6	Capitalized Overhead	146	148	150	152	153	155	157	159	161	163
Row 8	Retirement	0	0	0	0	0	0	0	0	0	0
Row 9	Closing Balance	38,374	65,103	88,342	90,159	91,759	92,643	93,062	93,411	94,262	94,461
Row 10											
Row 13	**Accumulated Depreciation**										
Row 14	Opening Balance	0	-557	-2,019	-4,120	-6,536	-9,000	-11,499	-14,016	-16,542	-19,106
Row 15	Depreciation	-557	-1,462	-2,101	-2,416	-2,464	-2,499	-2,516	-2,526	-2,564	-2,572
Row 16	Retirement	0	0	0	0	0	0	0	0	0	0
Row 17	Closing Balance	-557	-2,019	-4,120	-6,536	-9,000	-11,499	-14,016	-16,542	-19,106	-21,678
Row 18											
Row 19	Net Fixed Assets	37,817	63,084	84,222	83,623	82,758	81,144	79,046	76,869	75,156	72,783

Table Enbridge 7-3

Updated Projected External Funded Fixed Assets

(Thousands of Dollars)

	Description	Col. 1 2019	Col. 2 2020	Col. 3 2021	Col. 4 2022	Col. 5 2023	Col. 6 2024	Col. 7 2025	Col. 8 2026	Col. 9 2027	Col. 10 2028
Row 1											
Row 2	**Gross Fixed Assets**										
Row 3	Opening Balance	0	8,663	22,328	22,328	22,328	22,328	22,328	22,328	22,328	22,328
Row 4	External Funding	8,535	13,465	0	0	0	0	0	0	0	0
Row 5	Reduction in Interest During Construction	128	201	0	0	0	0	0	0	0	0
Row 6	Retirement	0	0	0	0	0	0	0	0	0	0
Row 7	Closing Balance	8,663	22,328	22,328	22,328	22,328	22,328	22,328	22,328	22,328	22,328
Row 8											
Row 9	**Accumulated Depreciation**										
Row 10	Opening Balance	0	-125	-594	-1,195	-1,796	-2,397	-2,998	-3,599	-4,200	-4,801
Row 11	Depreciation	-125	-469	-601	-601	-601	-601	-601	-601	-601	-601
Row 12	Retirement	0	0	0	0	0	0	0	0	0	0
Row 13	Closing Balance	-125	-594	-1,195	-1,796	-2,397	-2,998	-3,599	-4,200	-4,801	-5,402
Row 14											
Row 15	Net Fixed Assets	8,538	21,735	21,134	20,533	19,932	19,331	18,729	18,128	17,527	16,926

Table Enbridge 7-4
Updated Projected Fixed Assets Net of External Funded Fixed Assets

(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1											
Row 2	**Gross Fixed Assets**										
Row 3	Opening Balance	0	29,711	42,774	66,014	67,831	69,430	70,315	70,734	71,083	71,933
Row 4	Capital Expenditure	29,225	12,723	22,747	1,639	1,422	716	255	185	677	33
Row 5	Interest During Construction	340	193	342	27	24	13	6	5	13	3
Row 6	Capitalized Overhead	146	148	150	152	153	155	157	159	161	163
Row 8	Retirement	0	0	0	0	0	0	0	0	0	0
Row 9	Closing Balance	29,711	42,774	66,014	67,831	69,430	70,315	70,734	71,083	71,933	72,133
Row 10											
Row 13	**Accumulated Depreciation**										
Row 14	Opening Balance	0	-432	-1,425	-2,925	-4,740	-6,604	-8,501	-10,417	-12,342	-14,305
Row 15	Depreciation	-432	-993	-1,500	-1,815	-1,863	-1,898	-1,915	-1,925	-1,962	-1,971
Row 16	Retirement	0	0	0	0	0	0	0	0	0	0
Row 17	Closing Balance	-432	-1,425	-2,925	-4,740	-6,604	-8,501	-10,417	-12,342	-14,305	-16,276
Row 18											
Row 19	Net Fixed Assets (Year End)	29,279	41,349	63,089	63,090	62,827	61,813	60,317	58,741	57,629	55,857
Row 20	Net Fixed Assets (Mid-year)	14,639	35,314	52,219	63,090	62,959	62,320	61,065	59,529	58,185	56,743

Enbridge 8

Reference: Exhibit 1, Tab 2, Schedule 1, page 38

Preamble: *"As detailed in Figure 1-3, there is a downward trend for OM&A costs per customer during the rate stability period. This reflects the fact that certain OM&A costs, including salaries, have a fixed element that has limited sensitivity to the number of customers served. This downward trend also reflects the efficiencies that EPCOR incorporated into its revenue requirement due to the competitive pressures brought to bear as a result of the Board's competitive process."*

Questions:

Please provide details of the efficiencies that EPCOR has incorporated into its revenue requirement and which cost categories these amounts are found in Table 1-9.

Responses:

In preparing its CIP, EPCOR completed a rigorous review of all the cost drivers of the proposed Southern Bruce utility. Cost controls and efficiencies that EPCOR was of the view it could implement over the 10-year rate stability period were then incorporated into each cost category and resulted in the revenue requirement included in its CIP. In determining that it had the lowest cost of delivery of natural gas to the Southern Bruce region, the OEB accepted the 10-year revenue requirement as proposed by EPCOR in its CIP.

Enbridge 9

Reference: Exhibit 1, Tab 2, Schedule 1, page 54

Preamble: *"The criteria used by EPCOR in determining to propose the establishment of the deferral accounts noted above includes:*

i. *the materiality of the amount at risk (revenue or expense);*

ii. *protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;*

iii. *the level of uncertainty associated with a forecast of the amount at risk; and*

iv. *the factors which influence the variance amount are beyond EPCOR's control and are not factors which EPCOR agreed would be at its risk as part of the competitive process."*

Reference: Filing Requirements for Natural Gas Rate Applications (dated February 16, 2017)

Preamble: *According to the current Filing Requirements for Natural Gas Rate Applications, an applicant seeking an accounting order to establish a new deferral or variance account must submit evidence of how the following eligibility criteria will be met:*

- *Causation – The forecasted expense must be clearly outside of the base upon which rates were derived*
- *Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements*
- *Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers*

The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement. The default materiality thresholds for the establishment of new deferral accounts are as follows:

- *$50,000 for a utility with a revenue requirement less than or equal to $10 million*
- *0.5% of revenue requirement for a utility with a revenue requirement greater than $10 million and less than or equal to $200 million*
- *$1 million for a utility with a revenue requirement of more than $200 million*

Questions:

(a) Please provide an explanation for why EPCOR has established a different set of criteria for its proposed deferral and variance accounts from those established by the OEB.

(b) Please provide details of the materiality thresholds that EPCOR has established for each of its proposed deferral and variance accounts.

Responses:

(a) EPCOR has not established a different set of criteria for its proposed deferral and variance accounts from those established by the OEB. Exhibit 1, Tab 2, Schedule 1, page 54 states that the criteria listed were *included* in the criteria used by EPCOR in determining whether to propose the establishment of deferral and variance accounts as a part of this Application. In addition to considering the items listed in Exhibit 1, Tab 2, Schedule 1, page 54, EPCOR completed an assessment of each proposed account under the causation, materiality and prudence criteria outlined in the Filing Requirements for Natural Gas Applications.

(b) For the purposes of assessing each proposed deferral and variance account under the OEB's eligibility criteria of materiality as outlined in the Filing Requirements for Natural Gas Applications, EPCOR Southern Bruce applied a materiality threshold of $50,000 which is consistent with the materiality threshold for EPCOR's Aylmer utility. Once established, all approved deferral accounts will be identified and brought forward for disposition annually or as otherwise directed by the OEB, regardless of the account balance.

Enbridge 10

Reference: Exhibit 3, Tab 2, Schedule 2

Preamble: *Municipal Bylaws and Franchise Agreements*

"4. Duration of Agreement and Renewal Procedures.

a. If the Corporation has not previously received gas distribution services, the rights hereby given and granted shall be for a term of 20 years from the date of final passing of the By- law.

b. At any time within two years prior to the expiration of this Agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise upon such terms and conditions as may be agreed upon. Until such renewal has been settled, the terms and conditions of this Agreement shall continue, notwithstanding the expiration of this Agreement. This shall not preclude either party from applying to the Ontario Energy Board for a renewal of the Agreement pursuant to section 10 of the Municipal Franchises Act."

Reference: OEB 2000 Model Franchise Agreement

Preamble: *"4. Duration of Agreement and Renewal Procedures*

a. If the Corporation has not previously received gas distribution services, the rights hereby given and granted shall be for a term of 20 years from the date of final passing of the By- law.

Or

b. If the Corporation has previously received gas distribution services, the rights hereby given and granted shall be for a term of 20 years from the date of final passing of the By-law provided that, if during the 20 year term of this Agreement, the Model Franchise Agreement is changed, then on the 7th anniversary and on the 14th anniversary of the date of the passing of the Bylaw, this Agreement shall be deemed to be amended to incorporate any changes in the Model Franchise Agreement in effect on such anniversary dates. Such deemed amendments shall not apply to alter the 20 year term.

c. At any time within two years prior to the expiration of this Agreement, either party may give notice to the other that it desires to enter into negotiations for a renewed franchise upon such terms and conditions as may be agreed upon. Until such renewal has been settled, the terms and conditions of this Agreement shall continue, notwithstanding the expiration of this Agreement. This shall not preclude either party from applying to the Ontario Energy Board for a renewal of the Agreement pursuant to section 10 of the Municipal Franchises Act."

Reference: RP-1999-0048 – Report to the Board, December 29, 2000, page 28

Preamble: *“The Panel is concerned that the wording suggested by AMO and the Gas Companies is ambiguous. It is important to clarify that the initial term is 20 years if the municipality has not previously received gas distribution services. In all other circumstances the term is for 20 years, and if the 2000 MFA is changed, except for the 20-year term, then on the 7th anniversary and the 14th anniversary the franchise would have the option of performing the obligation at the defaulting party's expense, or taking action for an order of specific performance directing the defaulting party to fulfill its obligations under the franchise agreement, and, if successful, all legal costs related to such court action would be paid by the defaulting party to the non-defaulting party on a solicitor/client basis.”*

Questions:

In EPCOR’s opinion, does the phrase from clause 4(b) in the Model Franchise Agreement “if the Corporation has previously received gas distribution services” refer to gas distribution service from the same distributor with whom the municipality is signing the agreement or does it refer to any supplier of gas distribution services?

Responses:

This is a matter that is being considered in EPCOR’s Leave to Construction application for Southern Bruce (EB-2018-0263). The issue of Franchise Agreements is outside the scope of this application.

Enbridge 11

Reference: Exhibit 10, Tab 1, Schedule 1

Preamble: *For the duration of the Custom IR period (i.e., years 2 through 10, from 2020 through 2028 inclusive), EPCOR is proposing a rate adjustment mechanism that would adjust rates annually. This mechanism is composed of two elements and is intended to affect both the "Stabilization Factor" EPCOR applied when calculating the cumulative revenue requirement in its CIP as well as the inflation factor imbedded in OM&A expenses. Each of these values (cumulative revenue requirement and forecast inflation) are as determined by the OEB's Southern Bruce Expansion Decision. The Stabilization Factor was applied against that part of the annual revenue requirement other than that necessary to recover OM&A expenses. The Stabilization Factor and forecast inflation used by EPCOR in determining its revenue requirement was 1.27%.*

EPCOR is proposing that the annual Incentive Rate Adjustment include a factor to adjust the forecast inflation factor applied to the OM&A portion of the Monthly Fixed Charge and Delivery Charge of each rate schedule to reflect actual inflation. In addition, the Stabilization Factor of 1.27% be applied against the remaining portion of Distribution Charges. For ease of calculation, EPCOR is proposing that in each year's IR adjustment, inflation be applied against 31.6% of that year's Distribution Charges for each rate class (i.e., cumulative distribution revenue requirement is $58.141 million and cumulative OM&A is $18.36 million so cumulative OM&A is $18.36M / $58.141M = 0.3158 of cumulative distribution revenue).

EPCOR proposes to calculate the inflation factor by using a 2-factor Input Price Index (IPI) methodology. To calculate the 2-factor IPI, EPCOR proposes to use the year-over-year change in the GDP-IPI (FDD), and the AWE (Average Weekly Earnings) All Employees-Ontario. The percentage change will be calculated as the weighted sum of 70% of the annual percentage change in the GDP- IPI (FDD) for the prior year relative to the index value for two years prior and 30% of the annual percentage change in the AWE for the prior year relative to the data for two years prior.

EPCOR is not proposing any productivity or stretch factors in its annual rate adjustment formula claiming that it has already applied productivity and stretch factors into in the proposed 10-year revenue requirement.

EPCOR's proposed Custom IR plan does not include an Earnings Sharing Mechanism (ESM) because, in EPCOR's opinion, rate protection has already been incorporated as a result of the competitive process and the symmetrical risk related to achieving a rate of return on equity assumed by EPCOR.

Reference: Handbook to Utility Rate Applications, October 13, 2016, page 25

Preamble: *"Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included* *in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).*

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided."

Questions:

(a) Please provide details of where the explicit financial incentives for continuous improvement and cost control targets are included within EPCOR's application.

(b) Please explain in detail why EPCOR has not followed the OEB's directions that incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

(c) Please confirm EPCOR's understanding that an earnings sharing mechanism protects customers from a distributor realizing excess earnings.

(d) Please provide details of the regulatory process that EPCOR envisions for its annual rate adjustments.

Responses:

(a) Please see OEB 10.Staff.40.

(b) Please see OEB 10.Staff.40.

(c) Please see OEB 10.Staff.40.

(d) EPCOR proposes that the annual rate adjustment would follow a process that generally conforms with the Board's Chapter 3 Incentive Rate-Setting Application Filing Requirements for Electricity Distribution Rate Applications. This process is one that the Board has followed regarding EPCOR's Alymer operations.

Enbridge 12

Reference: Exhibit 10, Tab 1, Schedule 1, page 6

Preamble: *"EPCOR proposes an Incremental Capital Modules ("ICM") in its Customer IR Plan. An ICM would be filed in the event of capital expenditures associated with an expansion of the Southern Bruce system incremental to the system EPCOR included in its CIP."*

Reference: Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014 and Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016.

Questions:

Please confirm EPCOR's understanding that ICM applications during a deferred rate rebasing term are used to recover costs associated with qualifying incremental capital investment beyond what is normally funded through approved rates consistent with the OEB-established policy on ICM and that qualifying incremental capital investments are discrete projects that satisfy the criteria documented in the referenced OEB reports.

Responses:

EPCOR confirms that it is familiar with Board policies regarding ICM applications. Please see response to OEB.10.Staff.43

Enbridge 13

Reference: Exhibit 10, Tab 1, Schedule 1, page 7

Preamble: *"EPCOR proposes to include an adjustment for tax changes in its Custom IR plan. EPCOR proposes the 50/50 sharing of impacts of legislated tax changes from EPCOR's tax rates known at the time of this Application and embedded in the rates if approved by the OEB. EPCOR proposes the use of a rate rider (calculated annually as applicable) for these amounts to be recovered from or refunded to customers over a 12-month period."*

Questions:

Please explain why EPCOR would not use a deferral account to track tax changes as has been determined by the OEB in previous proceedings.

Responses:

See response to 10.Staff.44.

IGUA 1

Reference: Ex1/T2/S1/p8.

Preamble: *The evidence indicates that EPCOR will "[e]xecute an interconnect agreement with Union, including incorporation of the appropriate tariff service".*

Questions:

(a) Please provide an update on discussions with Enbridge Gas (EG) regarding the requisite interconnection agreement.

(b) Please provide any draft agreements provided to EPCOR.

(c) Please explain what EPCOR means by the phrase "appropriate tariff service". Please include in the explanation what EPCOR considers to be the appropriate tariff service, and the status of discussions with EG in this respect.

Responses:

(a) EG and EPCOR are engaged in ongoing discussions. At this time, the parties have not reached agreement as to a final interconnect agreement. Please see EB-2018-0244 for the most recent filings on the EG request for the proposed M17 tariff.

(b) EPCOR declines to provide draft agreements as they may not be reflective of any final agreement and would therefore not be of use. EPCOR notes that the economic terms of these drafts have been reflected in the proposed rates in this application.

(c) EPCOR is of the view that the Southern Bruce Project should have access to EG's M9 tariff. To date, EG has not agreed to this request. The matter is presently being adjudicated by the Board. Please see EB-2018-0244 for details of EG's filing related to the proposed M17 tariff.

IGUA 2

Reference: Ex1/T2/S1/p32

Preamble: *Table 1-5 in the evidence seems to indicate that EPCOR expects adding 2 Rate 16 customers every year starting in 2019, for a total of 20 Rate 16 customers by 2028.*

Reference: Ex3/T1/S2/p2

Preamble*:* *Table 3-9 indicates a relatively steady assumed throughput volume for Rate 16 customers for the years 2020 through 2028.*

Questions: Please confirm EPCOR's assumption regarding the number of Rate 16 customers over the rate stability period (customer numbers by year).

Responses:

Table 1-5 summarizes the total customers in each rate class per year, not the incremental customers by year. EPCOR is forecasting to have a total of 2 industrial customers starting in 2019. The values in Column 11 are a sum of the values in each row of the table. These values are subject to the revised forecast in Exhibit 6.

IGUA 3

Reference: Ex1/T2/S1/p41, paragraph 31.

Preamble: *The evidence states, in reference to the cost allocation study filed;*

EPCOR notes that the Study is useful as it serves as a comparison and a reasonableness check of the rates and resulting revenue proposed to be recovered from each rate class. However caution should be exercised in attempting to rely on it to directly establish rates for the utility.

Questions:

(a) Did EPCOR establish its proposed rates using the cost allocations reflected in the study?

(b) If not, please clarify precisely how EPCOR established its proposed rates, including details of any deviations from the cost allocation study (both as to quantum and rationale) and what EPCOR asserts the Board should take from the cost allocation study.

Responses:

(a) Please see Exhibit 7.1 for discussion on the process ECPOR used in rate design. Also, please see OEB 7.Staff.22(a).

(b) Please see OEB 7.Staff.22(a).

IGUA 4

Reference: Ex1/T2/S1/pp.42-43/Tables 1-12 and 1-13

Preamble: *Table 1-13 indicates that customers in Rate Classes 16 and 11 will cross-subsidize EPCOR's other customers.*

Ex2/T1/S1/p3/paragraph 3 addresses EPCOR's treatment of the value of external funding.

Questions:

(a) Please explain why it is appropriate that Rate 16 and Rate 11 customers cross- subsidize EPCOR's other customers.

(b) Please file a set of rates which eliminate all cross-subsidies (i.e. for which revenue to cost ratios are 1.0 for each of EPCOR's proposed rate classes).

(c) Please explain in detail the impacts of proceeding with the rates provided in response to part (b) of this question as opposed to the rates as proposed by EPCOR.

(d) Please explain in detail how EPCOR's proposal to allocate the $22 million in external funding results in the revenue to cost ratio differences illustrated in Table 1-12 as compared to table 1-13. Please provide full calculations and continuities to illustrate the changes between the two tables.

(e) The evidence at Ex7/T1/S1/p5 indicates that "EPCOR has allocated the proceeds from external funding in a manner that is aligned with general cost allocation principles". Please;

i. explain what those principles are;

ii. indicate how EPCOR's cost allocation "aligns" with those principles; and

iii. indicate and quantify any proposed deviations from strict application of those principles.

Responses:

(a) Please see OEB 7.Staff.22(a).

(b) Table IGUA 4-1 details the impact of proposing a revenue to cost ratio that is the same for all rate classes.

Table IGUA 4-1

Distribution Revenue to Cost Comparison
(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	Description	Total	Rate 1 - General Firm Service	Rate 6 - Large Volume General Firm Service	Rate 11 - Large Volume Seasonal Service	Rate 16 - Contracted Firm Service
Row 1	Revenue	7,846.23	5,351.18	1,359.41	183.52	952.12
Row 2	Cost of Service	7,683.94	5,240.40	1,331.29	179.74	932.50
Row 3	Over / Under Contributions	162.29	110.77	28.12	3.78	19.62
Row 4	Revenue to Cost Ratio	1.02	1.02	1.02	1.02	1.02

Distribution Rates

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
	Description	Unit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1	**Rate 1 - General Firm Service**											
Row 2												
Row 3	Monthly Charge	($ / CX / Month)	25.00	25.32	25.64	25.96	26.29	26.63	26.97	27.31	27.66	28.01
Row 4												
Row 5	Commodity Charge											
Row 6	First 100 m3	(¢ / m3)	27.1829	27.5281	27.8777	28.2318	28.5903	28.9534	29.3211	29.6935	30.0706	30.4525
Row 7	Next 400 m3	(¢ / m3)	26.6551	26.9936	27.3364	27.6836	28.0352	28.3912	28.7518	29.1170	29.4867	29.8612
Row 8	Over 500 m3	(¢ / m3)	25.8792	26.2079	26.5407	26.8778	27.2191	27.5648	27.9149	28.2694	28.6284	28.9920
Row 9												
Row 10	**Rate 6 - Large Volume General Firm Service**											
Row 11												
Row 12	Monthly Charge	($ / CX / Month)	102.00	103.30	104.61	105.94	107.28	108.64	110.02	111.42	112.84	114.27
Row 13												
Row 14	Commodity Charge											
Row 15	First 1000 m3	(¢ / m3)	32.9529	33.3714	33.7952	34.2244	34.6590	35.0992	35.5450	35.9964	36.4535	36.9165
Row 16	Next 6000 m3	(¢ / m3)	30.4810	30.8681	31.2601	31.6571	32.0592	32.4663	32.8786	33.2962	33.7191	34.1473
Row 17	Over 7000 m3	(¢ / m3)	29.3686	29.7416	30.1193	30.5018	30.8892	31.2815	31.6788	32.0811	32.4885	32.9011
Row 18												
Row 19	**Rate 11 - Large Volume Seasonal Service**											
Row 20												
Row 21	Monthly Charge	($ / CX / Month)	204.00	206.59	209.21	211.87	214.56	217.29	220.05	222.84	225.67	228.54
Row 22												
Row 23	Commodity Charge											
Row 24	First 0 m3	(¢ / m3)	11.5017	11.6478	11.7957	11.9455	12.0972	12.2509	12.4064	12.5640	12.7236	12.8852
Row 25	Next 0 m3	(¢ / m3)	11.5017	11.6478	11.7957	11.9455	12.0972	12.2509	12.4064	12.5640	12.7236	12.8852
Row 26	Over 0 m3	(¢ / m3)	11.5017	11.6478	11.7957	11.9455	12.0972	12.2509	12.4064	12.5640	12.7236	12.8852
Row 27												
Row 28	**Rate 16 - Contracted Firm Service**											
Row 29												
Row 30	Monthly Charge	($ / CX / Month)	1,500	1,519	1,538	1,558	1,578	1,598	1,618	1,639	1,659	1,680
Row 31												
Row 32	Capacity Charge	month / m3 Contrac	75.5990	76.5591	77.5314	78.5160	79.5132	80.5230	81.5457	82.5813	83.6301	84.6922

(c) Please see OEB 7.Staff.22(a).

(d) EPCOR proposes to allocate the $22.0 million of external funding to distribution plant on a pro-rata basis to assets scheduled to be constructed in 2019 and 2020. The allocations to the distribution plant categories are summarized in Table IGUA 4-2.

Table IGUA 4-2

Allocation of External Grant Funding

Table Reference[1]	Distribution Plant	$ 000's	% of Total
2-11	Distribution Mains - Metallic	11,292	51.3%
2-12	Land Rights	16	0.1%
2-13	Distribution Mains - Plastic	9,494	43.2%
2-14	Distribution Services	553	2.5%
2-15	Distribution Meters	0	0.0%
2-16	Measuring & Regulating Equip.	644	2.9%
2-17	Vehicles	0	0.0%
2-18	Machinery and Equipment	0	0.0%
	Total	**22,000**	**100.0%**

Note 1 EB-2018-0264, Exhibit 2, Tab 2, Schedule 1, Table 2-11 to 2-18, Row 7

Table 1-13 presents the results of the cost allocation study assuming no external funding and no reduction to the distribution plant accounts as noted in Table IGUA 4-2 above. Table 1-12 incorporates the external funding. The allocation of external funding impacts the costs to be allocated in two ways; 1) a reduction in rate base and return on rate base, and 2) a decrease in annual depreciation expense. The determination of the total difference of $1,528,000 between Table 1-12 and Table 1-13 (Col.1, row 2) is presented in Table IGUA 4-3.

Table IGUA 4-3

External Funding Cost of Service Imact

	2027	2028
External Funding Net Fixed Asset - closing balance[1]	17,467	16,877
External Funding Rate Base (reduction) - Net PPE (average)		17,172
1. Return on Rate Base (reduction) (5.46% x Rate Base)	5.46%	938
2. Depreciation Expense (reduction)[2]		590
Total Impact of External Funding		**1,528**

Notes:

1 EB-2018-0264, Exhibit 2, Tab 1, Schedule 1, Table 2-3, Col.9 Row 15 and Col.10 Row 16

2 EB-2018-0264, Exhibit 2, Tab 1, Schedule 1, Table 2-3, Col.10 Row 11

Allocation of return on rate base and depreciation expense to each of the rate classes follows the same functionalization, classification and allocations used in the cost allocation study as detailed in the tables in Exhibit 7, Tab 1, Schedule 2, pages 1 - 21.

(e)

i. See Exhibit 7.3 for overview of the cost allocation principles.
ii. See Exhibit 7.4 for a description of how the cost allocation principles were applied.
iii. There is no deviation from the cost allocation principles/methodology as described in Exhibit 7.

IGUA 5

Reference: Ex1/T2/S1/p44/paragraph 40

Preamble: *The referenced evidence describes EPCOR's proposed Rate 16 rate class, including EPCOR's proposal to set the minimum daily demand for rate class qualification at 2,739m3.*

Questions:

(a) Please file a copy of the most current draft of the proposed Rate 16 customer contract and any associated schedules.

(b) Please explain how the proposed minimum daily demand was derived and what EPCOR's objectives are in setting it as the minimum daily demand requirement for customers to qualify for Rate 16.

Responses:

(a) EPCOR is working with its large industrial customers to finalize the Rate 16 customer contract and has not confirmed the terms and conditions. However, the final contract is expected to include the following key terms.

i. Conditions Precedent

1. EPCOR has brought into service that portion of the Southern Bruce project necessary to service the customer
2. Customer has satisfactory creditworthiness
3. The final rate schedule approved by the OEB is within certain percent as that proposed by EPCOR

ii. Term & Termination

1. Term is 15 years (this matches the term of the transmission agreement related to Rate 16 transmission services that EPCOR expects to execute with Enbridge).
2. Customer may reduce a portion of its contract demand by paying out value of contract.
3. Contract may be terminated by customer if EPCOR does not provide service within a certain period after execution of contract.

iii. Distribution Service

1. EPCOR will receive Gas from Customer at agreed to location (e.g. Dawn Hub) and deliver to Customer at Point of Consumption

2. Subject to certain provisions, EPCOR agrees to provide Firm Gas distribution service

3. Subject to certain conditions, EPCOR agrees to provide Authorized Overrun Gas supply

4. Subject to availability, Customer may increase its Contract Demand. Subject to certain terms, Customer may subsequently reduce that increase.

iv. Customer Creditworthiness Requirements

1. Any financial assurances required will be based on the Customer's credit rating as determined by EPCOR. EPCOR has right to request updated financial information.

v. Measurement

1. EPCOR will provide Customer access to real-time data from equipment operated by EPCOR.

vi. Maintenance, Service Suspensions and Curtailment

1. All provisions of the General Terms and Conditions regarding Service Suspension, Curtailment and Maintenance shall apply. EPCOR will use reasonable efforts to provide 30 days notice of any planned maintenance or construction and coordinate such with Customer's shut down periods.

vii. Charges and Rates

1. Charges and rates to be billed for by EPCOR, and paid for by the Customer, shall be those applicable charges set out in the Rate 16 Schedule.

viii. Notice

1. All communications shall be in writing and delivered to applicable address.

ix. General

1. Governing Law is Province of Ontario

2. Conflict – in case of conflict between this Contract (including General Terms and Conditions) and the Rate 16 Schedule, the Rate 16 Schedule shall prevail, followed by the Contract, followed by the General Terms and Conditions and then Conditions of Service.

3. Application of General Terms and Conditions – Customer may opt out of future amendments to the Terms and Conditions unless those amendments are related to safety or changes in law or regulation.

x. Schedule A – Contract Parameters

1. This schedule details the Contract Demand, including Peak Hour of the customer. It also confirms the Point of Consumption of the Customer and where the Customer will be delivering gas e.g. Dawn Hub.

xi. Schedule B – Rate Schedule

1. This schedule includes a copy of the Rate 16 tariff applied for

xii. Schedule C – Termination Payment

1. This schedule details cost to the Customer of reducing part of its Contract Demand. The intent is that EPCOR, and all other rate payers, are not disadvantaged if the Customer partially reduces its Contract Demand. This is accomplished by requiring the Customer to pay the outstanding value of any reduction in the Contract Demand.

xiii. Schedule C – General Terms and Conditions

1. This schedule refers to the most recent terms and conditions as approved by the OEB.

xiv. Schedule D – Conditions of Service

1. This schedule refers to the most recent terms and conditions as approved by the OEB

xv. Schedule F – Security Requirements

1. This schedule details the value of any credit granted and / or schedule of security required specific to a customer

(b) The rate classes have been established based on grouping customers with similar characteristics into the same rate class. In the case of Rate 16, customers must take service from the high-pressure distribution system, be willing to enter into a contract, and have a minimum contract demand (CD) of 2,739 m3/day. The CD volume is based on an annual volume of 1,000,000 m^3. In the process of designing the rates, the minimum CD was adopted because it provided a reasonable breakpoint with the next group of customers (Rate 11). EPCOR also considered the minimum CD for similar sized customers in neighbouring Union Gas's service area which is the M4 rate which has a CD of 2,400 m^3/day.

IGUA 6

Reference: Ex1/T2/S1/p61/Table 2-7

Preamble: *Rows 1-5 of the referenced table address the costs to ECPCOR of Enbridge Gas' (EG) Owen Sound Reinforcement.*

Questions:

(a) Please indicate the date used for the Owen Sound Reinforcement to be in service in deriving the referenced costs.

(b) Please provide an update on discussions with EG regarding the date at which the Owen Sound reinforcement is necessary to ensure continuing service to EPCOR. If this date is different from that assumed in the referenced table, please indicate the dollar value to EPCOR of the deferred in-service date.

(c) Is EPCOR aware of discussions between EG and a large customer currently taking service from EG at Mount Forest (upstream of Dornoch) regarding turn back of that customer's capacity and the impact of that turn back on the need date for EG's Owen Sound reinforcement in providing service to EPCOR? If so, please provide any information on this circumstances of which EPCOR is aware and discuss the implications of that information for EPCOR's plans and costs to serve.

(d) Will any cost reduction resulting from deferral of the Owen Sound reinforcement be included in the proposed CIAC Deferral Account?

Responses:

(a) November 1, 2019.

(b) EPCOR understands that EG has the ability provide the required capacity using current transmission assets until 2020. EPCOR has not confirmed what dollar impact this may have on the values in the referenced table.

(c) EPCOR understands that EG held a reverse open season and certain capacity was turned back. EPCOR is not aware of any further details, including the impact of any capacity that may have been turned back on the need date for EG's Owen Sound reinforcement.

(d) Potential cost reductions resulting from deferral of the Owen Sound reinforcement could result in a reduction in the CIAC or rate charged by EPCOR. A cost reduction that is not reflected in updated rates, but an increase in CIAC will be reflected in the CIAC Deferral Account.

IGUA 7

Reference: Ex2/T1/S1/p62, paragraph 4

Preamble: *The evidence addresses treatment of construction work in progress and states; "…all Capital Expenditures are assumed to be accumulated at the OEB prescribed rate for six months to reflect that construction of the more expensive high pressure mainline assets will take place early in the construction season."*

Questions:

(a) Please provide the value of construction work in progress (CWIP) assumed for 2019.

(b) Please provide the value of CWIP actually expected for 2019.

Responses:

(a) EPCOR currently assumes $31,776k of CWIP for 2019. Of this amount, $31,308k is the cost of capital expenditure net of external funding and excluding the contribution to Enbridge Gas for the Owen Sound reinforcement and its station upgrade, $468k is the assumed interest during construction.

(b) $31,776k is EPCOR's expected CWIP for 2019.

IGUA 8

Reference: Ex2/T2/S1/p7

Preamble: *The evidence indicates 2 steel pipelines; an NPS 8 from Dornoch to the Bruce Energy Centre and an NPS 6 from the Bruce Energy Centre to Kincardine. The evidence further indicates MDPE pipelines downstream of Kincardine. The evidence indicates 4 stations between Dornoch and the Bruce Energy Centre and 3 stations downstream of the Bruce Energy Centre.*

Questions: Please provide a modification of Table 1 – Summary of Managed Assets, which adds:

(a) A column which provides the capital cost of each of the assets listed in the table.

(b) Columns for each proposed rate class which indicates the allocation of the cost of each of the assets listed in the table to that rate class.

Response:

A modified version of Table 1 is provided below. The first modification (a) includes two columns which provide i) the amount of capital investment in 2019, 2020, and ii) the rate base in 2028. The second modification (b) provides the allocation of the 2028 rate base to each of the rate classes.

Table IGUA 8-1
Summary of Managed Assets

	Facility	Approximate Length (km)	Description	Capital Investment $000's	Rate Base 2028[1] $000's	Rate 1	Rate 6	Rate 11	Rate 16
Pipelines	Dornoch to Bruce Energy Center	60	SteelNPS 8	29,897	15,629	5,947	3,614	426	5,642
	Bruce Energy Center to Kinkardine	15	SteelNPS 6	6,927	3,621	1,378	837	99	1,307
	Kincardine to Lucknow	41	MDPE NPS 6	7,221	4,142	2,902	1,101	139	0
	Kincardine Bypass Line	5	MDPE NPS 6	1,342	747	523	198	25	0
	Community Distribution Piping	178	MDPE NPS 2 & 4	23,594	13,726	9,617	3,647	462	0
Stations	**Facility**	**Description**							
	Dornoch	Metering Station		254	119	45	22	4	48
	Chelsey	Pressure Regulating Station		158	78	30	14	3	32
	Paisley	Pressure Regulating Station		161	80	30	15	3	32
	Bruce Energy Center	Pressure Regulating and Metering Station		218	102	39	19	3	41
	Tiverton	Pressure Regulating Station		158	74	28	14	2	30
	Inverhuron	Pressure Regulating Station		142	70	27	13	2	28
	Kincardine	Pressure Regulating Station		224	105	40	19	4	42
	Total			70,296	38,493	20,606	9,513	1,171	7,203

Note 1 Rate base value included in the cost allocation study for the year 2028 (net of external funding and depreciated)

IGUA 9

Reference: Ex7/T1/S2/Tables 7-5, 7-15 and 7-24

Preamble: *Table 7-5 indicates that the rate base for the Distribution Mains-Metallic (8" and 6" steel pipe) is functionalized as Distribution Mains H.P. Steel and then Distribution Mains H.P. Steel is classified as Capacity HP. The Capacity HP costs are allocated across all Rate classes with Rate 16 being allocated 36%.*

Questions:

(a) Please confirm that the two currently identified Rate 16 customers are located upstream of the 6" steel pipe from the Bruce Energy Centre to Kincardine.

(b) If confirmed, please indicate the basis on which costs of the 6" steel pipe are allocated to Rate 16.

(c) Please provide the detailed calculation used to derive the 36% allocation to Rate 16 referenced.

(d) Please indicate how the rate 16 cost allocations and rates would change if the currently allocated 6" steel pipe costs are removed from rate 16 allocations, and provide supporting quantification and calculations of the changes.

Responses:

(a) Confirmed.

(b) The distribution system has been designed with consideration to all customers connecting to the system and was not designed as discreet assets that only serve one customer or rate class. There are significant cost savings and economies of scale by building a shared distribution system that in turn benefits all customers. Since all customers will benefit from the cost minimization strategy of a shared system, all customers should be expected to share in the cost of the system.

From a technical perspective, the high-pressure distribution system of 8" and 6" steel mains have been designed to operate as a single high-pressure system that serves all customers and is not two independent systems. The Bruce Energy Centre (BEC) load impacts the design of the high-pressure steel mains both upstream and downstream of the BEC connection point. For instance, a decrease in the BEC design load which would reduce overall pressure losses on the high-pressure system, could result in the size of the 6" pipeline to Kincardine being reduced. Conversely, an increase in the BEC design load which would increase the overall pressure losses on the high-pressure system, could potentially be accommodated by increasing the size of the 6" line to Kincardine.

In terms of cost allocation, customers taking service on the high-pressure system (as do Rate 16 customers) will share in the costs of the high-pressure system regardless of where the connection point is. This same methodology has consistently been applied on the low-pressure distribution system where two customers in the same rate class pay the same rates regardless of where on the distribution system they connect. As a result of applying this methodology, customers in the same rate class are being treated equally and there is no advantage or disadvantage to being located either up-stream or down-stream on the distribution system.

An undesirable consequence of not treating the entire high-pressure system as a single entity is that it opens the possibility of customers requesting adjustments for their point of connection. As an example, this could include communities which have radial connections to the high-pressure system up-stream of the BEC. Permitting this would require the creation of new rate classes that account for each specific connection point and would ultimately concentrate the allocation of costs to those customers who take service from the end point of the high-pressure system.

Based on the discussion above, Rate 16 customers have been allocated a portion of the entire high-pressure distribution system including a portion of the 6" high-pressure pipeline.

(c) The 36% is based on the weighted peak allocation factor (WCP 1) as presented in Exhibit 7, Tab 1, Schedule 2, page 9 of 21 in Row 5 of Table 7-23. The weighted peak allocation factor is the average of the coincident peak and non-coincident peak allocation factors as presented in Row 3 and Row 4 respectively of this same table.

(d) The cost of service for Rate 16 customers would decrease by $118k if the portion of the 6" steel mains cost allocated to Rate 16 was reduced to zero (0%) as detailed in the table below. It should be recognized that this calculation does not include any further adjustments as noted in part (b) of this IR for impacts on the size or length of the 6" steel main attributable to the load at the BEC, or for the cost of the radial pipeline connecting the BEC to the high-pressure system.

Table IGUA 9-1

Re-Allocation of 6" Steel Mains	**$ 000's**									
6" Steel Mains	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Closing Gross Fixed Assets (GFA)	6,810									
External Funding	-2,088									
Closing GFA Net of Funding	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722
Accumulated Depreciation	-67	-202	-337	-472	-607	-742	-877	-1,012	-1,147	-1,282
Closing Net PPE	4,654	4,519	4,385	4,250	4,115	3,980	3,845	3,710	3,575	3,440
Rate Base for 6" Steel Mains (2028)										3,508
RoRB									5.46%	192
Depreciation Expense										135
Total Return on Rate Base + Depreciatin Expense										326
Revised Allocation to R16	WCP 1								-36.1%	**-118**

IGUA 10

Reference: Ex2/T2/S1/p8, paragraph 5

Preamble: *The evidence states; EPCOR will be expected to provide a contribution in aid of construction in the amount of $5.298 million related to the construction of Union's Dornoch Meter and Regulator Station and upstream transmission reinforcement.*

Questions: Please provide the allocation of EPCOR's CIAC costs to each proposed rate class.

Responses:

Enbridge has provided EPCOR with a forecast CIAC cost in 2019 of $5.298 million. The depreciated value included in rate base for 2028 is $4.185 million as presented in Exhibit 7, Tab 1, Schedule 2, page 10 of 21, Table 7-25, Col. 1, Row 5, and the allocation to each rate class is provided in Col. 2 to Col. 5 of Row 5. The allocation to each rate class is based on the coincident peak (CP 1) allocation factor as provided in Exhibit 7, Tab 1, Schedule 2, page 9 of 21, Table 7-23, Row 3.

The depreciation expense related to the Enbridge CIAC is presented in Exhibit 7, Tab 1, Schedule 2, page 10 of 21, Table 7-26, Col. 1, Row 5, and the allocation to each rate class is provided in Col. 2 to Col. 5 of Row 5. The allocation to each rate class is based on the coincident peak (CP 1) as described above.

IGUA 11

Reference: Ex3/T1/S1/p10, paragraph 6

Preamble: *The evidence presents the value to EPCOR of the Southern Bruce Municipalities tax holiday authorization, calculated to equal to $2.208 million over the 10 year rate stability period.*

Questions: Please provide the allocation of the tax holiday value to each proposed rate class.

Responses:

The cumulative value of the tax holiday over the 10 year rate stability period is $2.208 million as presented in Exhibit 3, Tab 1, Schedule 3, page 2 of 3, Table 3-14. The value of the tax holiday in the year 2028 when the cost allocation study was completed is $252,000 as shown in this same Table 3-14, Col. 11. The allocation of the tax holiday amount in 2028 to each rate class is summarized in the table below.

Table IGUA 11-1
Allocation of Tax Holiday ($000)

	Rate 1	Rate 6	Rate 11	Rate 16	Total
Allocation of Tax Holiday in 2028	136	63	8	46	252

IGUA 12

Reference: Ex3/T1/S2/p2

Preamble: IGUA understands Tables 3-8 and 3-9 to provide volume forecasts as assumed for the purposes of EPCOR's CIP submission.

Questions: Please update these tables to provide EPCOR's most recent volume forecasts.

Responses:

As per the Board's decision on the Southern Bruce competitive process "the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal"[1]. As a result, EPCOR has filed volume forecasts that are consistent with its CIP. These volume forecasts are the basis for the rates which have been proposed in the application and have not been updated.

[1] EB-2016-0137/0138/0139 Decision and Order South Bruce Expansion Applications, April 12, 2018, Section 4.2, page 11

IGUA 13

Reference: Ex4/T1/S1/p18, paragraph 38

Preamble*:* The evidence discusses an employee incentive plan which "reflects EUI (i.e. Corporate) and business level performance". Ex4/T1/S1/p21, Table 4-6 provides detail on employee expenses.

Questions:

(a) Please provide the percentage breakdown between "corporate" and "business level" tied Short-Term Incentive Pay.

(b) Please file a copy of the performance metrics that determine incentive pay awards.

Responses:

(a) The specifics of the employee incentive plan for Southern Bruce have not yet been developed.

(b) The performance metrics for the Southern Bruce utility have not yet been developed. EPCOR would expect that they will focus on safety, system performance and other metrics included in the proposed Performance Scorecard.

IGUA 14

Reference: Ex4/T1/S1/pp.22 et seq.

Preamble: *The evidence details shared corporate services and corporate cost allocation. Table 4-7 summarizes the allocation methods applicable to EUI's allocable Corporate Shared Services costs.*

Questions:

(a) Please provide the percentage which the EPCOR revenue requirement used for setting proposed rates represents of the sum of (total EUI 2018 revenue + the revenue requirement used for setting EPCOR's proposed rates).

(b) For each department and function listed in Table 4-7, please provide the percentage of total EUI departmental or function costs allocated to EPCOR.

(c) Please explain why costs associated with EOUI's Board of Directors (i.e. the "governance" function) is appropriately recovered from EPCOR ratepayers as a cost of providing gas distribution services, rather than retained by EOUI as a cost of minding its investment in EPCOR.

Responses:

(a) See response to 4-SEC-10.

(b) See response to 4.Staff.14 (a).

(c) See response to 4.Staff.15 (b).

IGUA 15

Reference: Ex4/T1/S1/p63, paragraph 5

Preamble: *The evidence discusses the tax credits from losses expected to be generated until the year 2025.*

Questions:

(a) Does EPCOR's proposed approach to setting rates credit ratepayers with the value of these tax credits from losses?

(b) If so, please explain in detail showing calculations.

(c) If not, please quantify the value of these tax credits from losses.

Responses:

(a) Yes.

(b) The tax credits were used in determining the revenue requirement in EPCOR's CIP. This revenue requirement was accepted by the Board in EB-2016-0137/0138/0139.

(c) See (b).

IGUA 16

Reference: Ex6/T1/S1/p3, Table 6-2.

Preamble: *The evidence summarizes the revenue deficiency components which EPCOR presents as applicable to the timeline for an OEB decision relative to the timeline assumed in EPCOR's CIP.*

Questions:

(a) Row 2 of the referenced table provides "Property Taxes" related foregone costs. Please confirm that these are not the same taxes in respect of which the South Bruce Municipalities have agreed to provide EPCOR with a tax holiday.

(b) Row 4 of the referenced table provides a figure for "deferred recovery of upstream changes", which are further described at page 7 of the referenced exhibit to include costs related to the CIAC to be paid to Enbridge Gas for, inter alia, the Owen Sound Transmission reinforcement.

i. What is the date of payment of the CIAC related to the Owen Sound reinforcement assumed in the figures presented in the referenced table?

ii. What is the actual expected date of payment of the CIAC related to the Owen Sound reinforcement?

iii. If the actual expected date is different from the date assumed in the table in the evidence, please restate the table to reflect the actual expected date.

Responses:

(a) Confirmed.

(b)

i. November 1, 2019.

ii. November 1, 2019 is EPCOR's current expected date of payment.

iii. See response to (ii) above.

IGUA 17

Reference: Ex7/T1/S1/p5

Preamble: *EPCOR used "proxy data and factors from the 2020 Fully Allocated Costing Study completed for EPCOR's Aylmer operation" in deriving its proposed rates.*

Questions: Please discuss the similarities and differences between EPCOR's Aylmer operation and the South Bruce expansion. Please include in the discussion information on;

(a) number of customers by type;

(b) nature of distribution services provided; and

(c) nature of distribution facilities used to provide services.

Responses:

In terms of the similarities between EPCOR Aylmer operation and the forecast for the Southern Bruce operation, they are both relatively small gas distribution utilities located in Ontario, regulated by the Ontario Energy Board and owned by EPCOR. From a practical standpoint of accessing the data needed to complete the cost allocation study, Aylmer was the preferred alternative as an Ontario based utility that is close in size, and the data was readily available.

The cost allocation study for EPCOR's Southern Bruce operation reflects the number and type of customers as forecast for this operation and does not rely on data from the Aylmer operation. While the nature of the distribution services is similar, the customer characteristics and load profiles have also been developed specifically for Southern Bruce customers. Similarly, the distribution facilities have been designed specifically to supply the load forecast for the Southern Bruce operation.

In situations where the forecasts for Southern Bruce did not provide the detail needed to complete the cost allocation study, functionalization and allocation values from EPCOR Aylmer's operation were used as a proxy. Specific cases where this was the case include:

- Functionalization of Rate Base - E7, T1, S1, page 8, par 4
    - Vehicles, and Machinery and Equipment functionalization percentages are from Aylmer
- Functionalization of O&M - E7, T1, S1, page 9, par 7
    - Salaries and Wages, Utilities, Billing and Collection, Insurance, Repairs and Maintenance, Vehicles and Travel functionalization percentages are from Aylmer
- Allocations Factors - E7, T1, S1, page 13, par 23
    - Allocation factors for Customer Weighted Meters (CusM) and Customer Weighted Billing (CusB) are from Aylmer

(a) The total customers forecast for Southern Bruce in 2028 is 5,274 and the total customers forecast for Alymer in 2020 is 9,538. The rate classes for the two utilities are not directly comparable, however, in general Rate 1 for Southern Bruce will correspond to Rate 1 Residential and Rate 1 Commercial for the Alymer utility. Rate 6 for Southern Bruce is a non contract service somewhat similar to the contracted Rate 3 for Alymer. Southern Bruce does not propose to offer an interruptible service similar to Alymer's Rate 4 and Rate 5. Rate 11 for Southern Bruce is a seasonal service as is Alymer's Rate 4. Rate 16 service for Southern Bruce is a contracted service for large industrial users which does not have a direct comparator in Alymer. Rate 6 service for Alymer involves a dedicated asset to service a single customer of which there is no direct comparator in Southern Bruce.

The forecast number of customers by rate class for South Bruce is provided in Table IGUA 17-1 (Exhibit 7, Tab 1, Schedule 2, page 21 of 21, Table 7-51, Row 13) and Aylmer in Table IGUA 17-2, below.

Table IGUA 17-1
Forecast South Bruce Customers

		Col. 1
	Rate Class	**Southern Bruce Customers**
Row 1	Rate 1	5,176
Row 2	Rate 6	91
Row 3	Rate 11	5
Row 4	Rate 16	2
Row 5	**Total**	**5,274**

Table IGUA 17-2
Forecast Alymer Customers

		Col. 1
	Rate Class	**Aylmer Customers**
Row 1	Rate 1 - Residential	8,877
Row 2	Rate 1 - Commercial	494
Row 3	Rate 1 - Industrial	68
Row 4	Rate 2	50
Row 5	Rate 3	6
Row 6	Rate 4	38
Row 7	Rate 5	4
Row 8	Rate 6	1
Row 9	**Total**	**9,538**

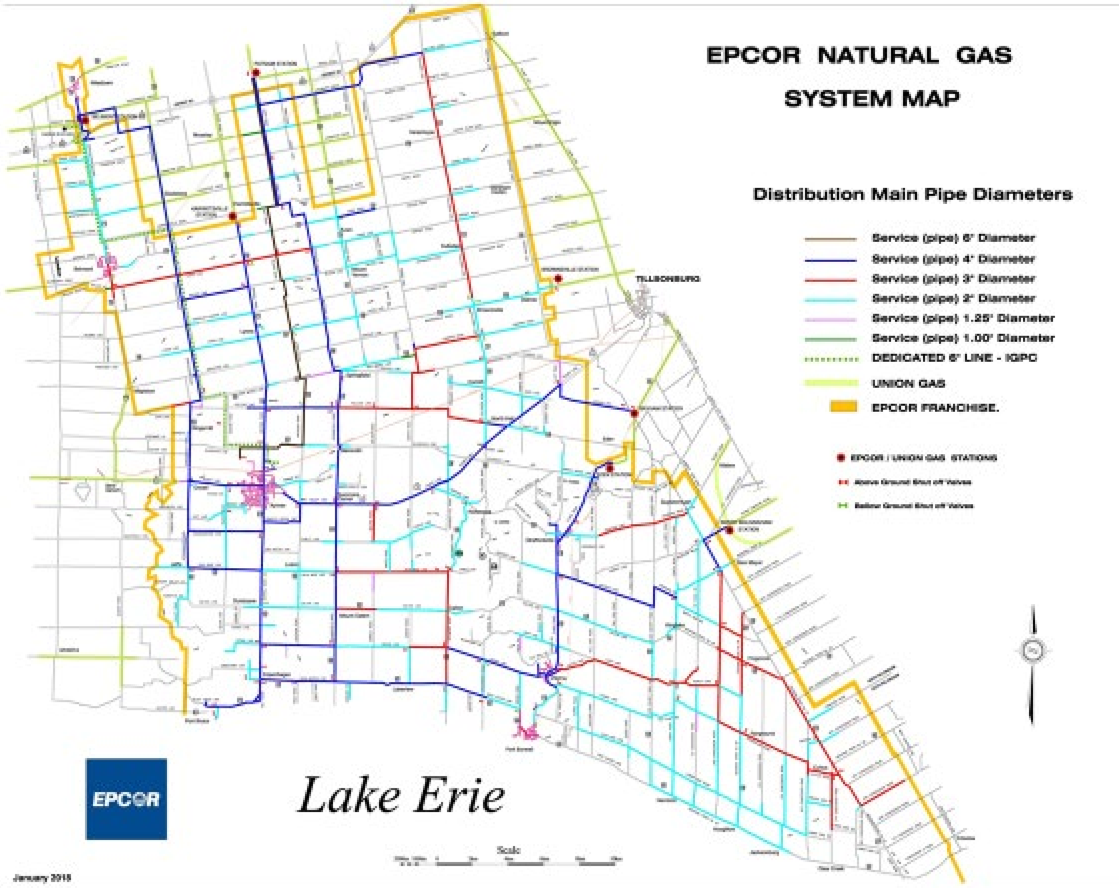
(b) See discussion above regarding similarities in rate classes between Southern Bruce and Alymer.

For Southern Bruce customers in Rate 1, 6 and 11 services include upstream delivery services (transportation, storage and load balancing), distribution delivery and gas supply unless otherwise elected by the customer. Rate 16 customers are provided delivery, transportation and some load balancing, but seasonal storage and gas supply services are not provided. The distribution, upstream and gas supply services are described in Exhibit 8, Tab 1, Schedule 1, Section 8.2.

For EPCOR's Aylmer operation, customers in Rate 1 through 5 are provided upstream delivery services, including storage and load balancing, and gas supply as a bundled service as Alymer has contracted with Enbridge Gas Inc. for its Rate M9 service. The customer in Rate 6 is provided distribution service on a dedicated high-pressure main. The customer procures its own gas supply services and transports it on Enbridge's transmission system using Alymer's M9 contract.

(c) Distribution system maps for South Bruce and Aylmer have been provided below.

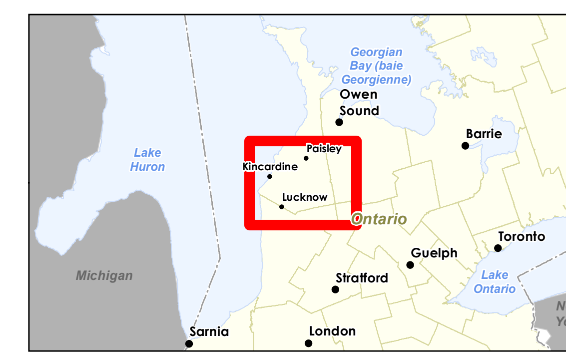
Aylmer Distribution Facility Map:



Legend
- Meter Station
- Distribution
- Kincardine Bypass
- Distribution Pressure Mainline System
- High Pressure Mainline Pipeline System
- Expressway / Highway
- Major Road
- -UG- Union Gas Pipeline (Approximately)
- Municipal Boundary - Lower Tier

0 5.5 11 Kilometers
1:275,000 (At original document size of 11x17)

Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources and Forestry © Queen's Printer for Ontario, 2016.



Project Location
Counties Of Bruce, Grey and Huron

160950831
Prepared by SPE on 2017-10-11
Technical Review by BCC on 2017-10-06

Client/Project
EPCOR SOUTHERN BRUCE GAS INC.\NATURAL GAS SERVICE SOUTHERN BRUCE

Figure No.
1-0

Title
Southern Bruce Mainline – Preliminary Preferred Route

IGUA 18

Reference: Ex7/T1/S1/p7

Preamble: *The evidence provides information on the functionalization adopted by EPCOR in its allocation of costs. Included in the list of functions is "Industrial Direct Assignment".*

Questions:

(a) Please provide a list of all costs functionalized as "Industrial Direct Assignment" by nature of cost and amount.

(b) Please indicate what rate class(es) such costs are assigned to (and if more than one rate class, how the costs are divided between the them).

Responses:

(a) The costs functionalized as Industrial Direct Assignment in the year 2028 are listed in the table below followed by additional descriptions of the cost items.

Table IGUA 18-1

Costs Functionalized as Industrial Direct Assignment for the Year 2028 - $ 000's

Row	Category	Description	Industrial Direct Assignment
1	Rate Base	Working Capital Allowance - Load Bal Admin + Enbridge Trans	19.66
2	Deferred Revenue	Deferred Upstream Recovery Costs - Industrial	58.95
3	O&M	Load Balancing Admin - Industrial	22.88
4	O&M	Enbridge Transportation - Industrial	207.84
5	Rate Base	Return on RB - Row 1 x Allowed Return (5.46%)	1.07
6	Deferred Revenue	Disposition of Deferred Revenue	2.88
7	Deferred Revenue	Carrying Cost of Deferred Revenue - Row 2 x LT Debt (3.72%)	2.19
8	Total[1]	Sum of Rows 3 to 7	236.87

Note 1: Reference Exhibit 7, Tab 1, Schedule 2, page 3 of 21, Table 7-11, Col. 7

Descriptions of functionalized costs:

1. Working Capital Allowance (Row 1) – working capital associated with load balancing administration costs and Enbridge transportation that is included in rate base.

2. Deferred Upstream Recovery Costs (Row 2) – Enbridge CIAC deferred recovery account balance for industrial customers. The disposition and carrying costs for this account are included in Rows 6 and 7 respectively.

3. Load Balancing Administration (Row 3) – load balancing administrative costs which have been allocated to industrial customers based on a volume weighting of 40% and coincident demand weighting of 60%.

4. Enbridge Transportation (Row 4) - upstream transportation charges directly attributable to industrial customers based on contracted demand.

5. Return on Rate Base (Row 5) – working capital amount of rate base (Row 1) multiplied by the allowed rate of return.

6. Disposition of Deferred Revenue (Row 6) – disposition amount of Enbridge CIAC in 2028.

7. Carrying Cost of Deferred Revenue (Row 7) – carrying cost of deferred upstream recovery (Row 2 multiplied by the long-term cost of debt).

8. Total (Row 8) – the sum of Rows 3 to 7.

(b) The Industrial Direct Assignment is assigned to Rate 16 customers only.

IGUA 19

Reference: Ex7/T1/S1/p10, paragraph 8 (continued)

Preamble: *The evidence indicates that some costs of the CIAC paid to Enbridge Gas are functionalized as "Upstream Transportation" and some are functionalized as "Industrial Direct Assignment".*

Questions: Please provide a further description of, including the amounts of, CIAC costs functionalized as "Upstream Transportation" and CIAC costs functionalized as "Industrial Direct Assignment", and explain the basis for such division.

Responses:

The evidence referenced in this interrogatory relates to deferred revenues presented in Table 7-9. There are three sources of deferred revenue;

I. Deferred Transportation and Storage Cost - Enbridge M17 transportation and storage charges that have not been recovered from Rate 1, 6 and 11. There are no unrecovered transportation and storage costs for Rate 16. As shown in Table 7-9 Row 1, the deferred transportation and storage cost of $526,150 has been functionalized 100% to Upstream Transportation (Col. 5). Costs functionalized as Upstream Transportation are allocated to Rate 1, 6 and 11 only.

II. Deferred Upstream Recovery Costs – Enbridge CIAC costs that have not been recovered from Rate 1, 6, and 11. The outstanding amount to be recovered in 2028 from Rate 1, 6 and 11 of $378,240 is shown in Table 7-9 Row 2 and is functionalized 100% to Upstream Transportation (Col. 5). As noted above no Upstream Transportation costs are allocated to Rate 16.

III. Deferred Upstream Recovery Costs (Rate 16) - Table 7-9 Row 3 presents the outstanding amount to be recovered in 2028 from Rate 16 of $58,950, which is functionalized 100% to Industrial Direct Assignment (Col. 7). Costs functionalized as Industrial Direct Assignment are allocated exclusively to Rate 16.

The Deferred Upstream Recovery Costs functionalized to Industrial Direct Assignment (Rate 16) and Upstream Transportation (Rate 1, 6 and 11) is summarized in Table IGUA 19-1 below.

Table IGUA 19-1

Functionalization of CIAC Costs for the Year 2028 - $ 000's

Row	Reference	Description	Industrial Direct Assignment	Upstream Transportation
1	Table 7-9, Row 3/2	Deferred Upstream Recovery Costs - Enbridge CIAC	58.95	378.24
2	Table 7-10, Row 3/2	Disposition of Deferred Revenue	2.88	18.45
3	Table 7-11, Row 6[1]	Carrying Cost of Deferred Revenue - Row 1 x LT Debt (3.72%)	2.19	14.07
4		Total (Row 2 + Row 3)	5.07	32.52

Note 1 - Carrying charge for Upstream Transportation includes CIAC only whereas Table 7-11, Row 6 Col. 5 includes CIAC (Table 7-9 Row 2, Col. 1) and Upstream Transportation and Storage Costs (Table 7-9 Row 1, Col. 1)

The portion of the cost of the CIAC to Enbridge allocated to Industrial Direct Assignment is based on the coincident peak demand (CP 1 of 39.36% as shown in Table 7-23, Row 3). The CIAC is treated as a rate base asset that is depreciated and earns the allowed rate of return. In the first few years of operation, revenues are not sufficient to recover the total cost of the CIAC and there is a revenue shortfall that is accumulated as a Deferred Upstream Recovery Cost. The amount of Deferred Recovery Cost is tracked for each rate class with the balance for Rate 1, 6 and 11 described in part II above, and Rate 16 described in part III. In the cost allocation study for the year 2028, revenues are sufficient to recover the CIAC payments and also pay-down a portion of the outstanding balance. This payment is the Disposition of Deferred Revenue as shown in Row 2 in the table above, and the cost of carrying the Deferred Upstream Recovery Cost balance is shown in Row 3 (Carrying Cost of Deferred Revenue).

IGUA 20

Reference: Ex7/T1/S1/p10, paragraph 9

Preamble: *The evidence indicates that some Deferred Upstream Recovery Costs are functionalized as "Upstream Transportation" and some are functionalized as "Industrial Direct Assignment".*

Questions: Please provide a further description of, including the amounts of, Deferred Upstream Recovery Costs functionalized as "Upstream Transportation" and those functionalized as "Industrial Direct Assignment", and explain the basis for such division.

Responses:

Please note the following correction to the referenced evidence Ex7/T1/S1/p10, paragraph 9 part iii which should be revised to include the added emphasized text:

> "iii. *Disposition of* Deferred Upstream Recovery Costs (Rate 16), recovery of CIAC costs are functionalized as Industrial Direct Assignment"

Given this change there is no Deferred Upstream Recovery Costs in Ex7/T1/S1/p10, paragraph 9 to describe or amounts to identify. The evidence referenced in this interrogatory relates to the disposition of deferred revenues presented in Table 7-10. The disposition of deferred revenues follows the same three deferred revenue accounts as described in IGUA IR 19 related to Deferred Upstream Recovery Costs. A brief description is provided below.

I. Disposition of Deferred Transportation and Storage Cost – Disposition of Enbridge M17 transportation and storage deferred revenues applied to Rate 1, 6 and 11. As shown in Table 7-10 Row 1, a disposition amount of $25,670 has been functionalized 100% to Upstream Transportation (Col. 5).

II. Disposition of Deferred Upstream Recovery Costs – Disposition of Enbridge CIAC deferred revenues applied to Rate 1, 6, and 11 in the amount of $18,450 is shown in Table 7-10 Row 2 and is functionalized 100% to Upstream Transportation (Col. 5).

III. Disposition of Deferred Upstream Recovery Costs (Rate 16) - Table 7-10 Row 3 presents the amount to be disposed from Rate 16 of $2,880, which is functionalized 100% to Industrial Direct Assignment (Col. 7).

IGUA 21

Reference: Ex8/T2/S2

Preamble*:* EPCOR has filed its General Terms and Conditions Rate 16 Customers.

Questions:

(a) Page 5, section 2: In the event of a Force Majeure on the Upstream Service Provider, will EPCOR receive relief of Upstream Charges? If yes, will this relief be passed on to EPCOR's Rate 16 customers?

(b) Page 5, section 3:

i. How will EPCOR allocate a "reasonable" proportion of Upstream Service Provider balancing rights to each Rate 16 customer?

ii. Please file a copy of any contract which EPCOR has executed with, or any draft contract that EPCOR has received from, the Upstream Service Provider (the latest version of these will suffice). (Please update this response if a contract or draft contract is subsequently received from the Upstream Service Provider.)

iii. Please provide a copy of the Upstream Service Provider's rate schedule for day-to-day load balancing.

(c) Page 6, section 4:

i. Will EPCOR provide consumption data in cubic meters on an hourly basis or daily basis?

ii. Will EPCOR also include the daily heat value so consumption data can be converted from cubic meters to gigajoules?

(d) Page 7, section 9: Please confirm that EPCOR industrial customers are only responsible for charges identified in its Rate 16 schedule.

(e) Page 11, section 17: Please confirm that the reference to "Monthly Fixed Charge" in the second last line of the second paragraph of section 17 is correct (and if not, please correct it).

Responses:

(a) Agreements with EPCOR's Upstream Service Provider (Enbridge) are not finalized. As set out in the *General Terms and Conditions Rate 16 Customers*, an event of force majeure upstream or downstream of EPCOR's system shall not relieve customers of any payment obligations. However, it is expected that if EPCOR received relief from Upstream Charges from an Upstream Service Provider, this would be passed on to customers through the proposed Storage and Transportation Variance Account for Rates 1, 6 & 11 and the Transportation Variance Account for Rate 16.

(b) Page 5, section 3:

i. At this time Enbridge has not confirmed the parameters of Upstream Service Provider balancing rights. As a result, EPCOR is unable to provide details as to how those balancing rights may be allocated.

ii. EPCOR has not executed any contracts with the upstream service provider. EPCOR is not in a position to provide draft agreements with Enbridge Gas as the parties are currently negotiating. The terms are subject to change and not appropriate for disclosure as they remain commercially confidential while under negotiation as it would force the parties to reveal negotiating and strategic positions and cause the agreements to effectively be negotiated in public.

iii. EPCOR has not received a final copy of the Upstream Providers rate schedule for day-to-day load balancing. EPCOR is not a position to provide this schedule for the same reason as noted in the previous paragraph.

(c) Page 6, section 4:

i. EPCOR intends to provide consumption data in cubic meters on a daily basis.

ii. If EPCOR has access to the daily heat value it will provide that information. At this time EPCOR has not confirmed whether it will have access to this information.

(d) ECPOR industrial customers will be responsible for charges identified in the Rate 16 Schedule, and as may otherwise be allowed by the OEB or as may be agreed to by the parties.

(e) "Monthly Fixed Charge" in the second last line of the second paragraph of section 17 is not correct. Monthly Fixed Charge should be replaced with "Delivery Charge". EPCOR will make this change in the final draft of this document.

IGUA 22

Reference: Ex9/T1/S1/p6, paragraph 29

Preamble: *EPCOR proposes an External Funding Variance Account (EFVA) to capture the differences between assumed and actual timing of payment of the external funding available to the project and actual timing.*

Questions: Please explain why this timing should be at ratepayer rather than shareholder risk.

Responses:

In its Decision and Order, the Board confirmed that "Both proponents were to use gross revenue requirement excluding any government grants, municipal contributions and Aids to Construction"[1]. As a result, in this application, the 10-year revenue requirement that was approved in the Board's Decision has been reduced by the value of the external funding[2]. This reduction is to the direct benefit of the ratepayer. Therefore, any difference in the timing of EPCOR receiving external funding versus what is currently forecast should be offset against this direct benefit.

[1] EB-2016-0137/0138/0139 Decision and Order South Bruce Expansion Applications, Section 4.1, Government Grants and Municipal Contributions and Aid to Construction, page 9
[2] Exhibit 3, Tab 1, Schedule 1, Table 3-5, page 11

IGUA 23

Reference: Ex10/T1/S1

Preamble: *EPCOR has not proposed an "off ramp" for its rate plan period.*

Questions: Please explain why EPCOR has not proposed an "off ramp" for its rate plan period, and why such a mechanism would not be appropriate.

Responses:

Please see OEB 10.Staff.40

1-SEC-1

Reference: Exhibit 1

Questions:

Please provide EPCOR's views on what aspects of the proposed approvals have already been determined by the Board's decision in EB-2016-0137/0138/139.

Responses:

As detailed in Exhibit 1.2.1, subject to the proposal for a revenue deficiency as detailed in Exhibit 6, EPCOR considers the following aspects as those that have already been determined by the Board in EB-2016-0137/0138/139. For additional detail please reference the paragraph number in Exhibit 1.2.1 as included in the following table.

Table 1-SEC-1-1

Aspects Determined by the Board in EB-2016-0137/0138/139

		Col. 1	Col. 2
	Exhibit 1.2.1 Paragraph	Aspect	Summary of Aspect
Row 1	5	Total customers	5,278 in 10-year period
Row 2	8	Rate Stability Period	10-years starting January 1, 2019
Row 3	9	Treatment of capital costs	EPCOR at risk for capital costs related to system included in CIP
Row 4	10	Revenue Requirement	10-year revenue requirement is $75.583 million
Row 5	12	Customer Consumption	Total volumes used in determining rates equals 342,186,741m^3
Row 6	13	Items not included in gross Revenue Requirement	• Government grants, municipal contributions and aid to construction • Demand-side management costs • Cap and Trade Costs • Tax holidays from municipality • Gas Commodity costs • Upstream reinforcement costs • Royalty payments if not recovered through revenue requirement
Row 7	14	Depreciation Rates	Use of Union's depreciation rates
Row 8	15	Capital Structure	• Debt/equity structure of 64/36. • Cost of debt and return on equity considered competitive and not held to OEB approved rates.
Row 9	16	Taxes	Use common tax rate of 26.5%
Row 10	17	Interest During Construction (IDC)	Use OEB prescribed rate

		Col. 1	Col. 2
	Exhibit 1.2.1 Paragraph	Aspect	Summary of Aspect
Row 11	18	Service Levels	Service levels meet those identified in Gas Distribution Access Rules
Row 12	19	Inflation Costs	Inflation applied in establishing 10-year gross revenue requirement in order to allow for comparison of CIP was 1.27%
Row 13		Z-Factor Mechanism	Utilities will have access to a Z-Factor mechanism
Row 14		Upstream costs	Upstream costs were not included in the revenue requirement proposed in the CIP.

1-SEC-2

Reference: Exhibit 1

Questions:

Please place on the record in this proceeding, a copy of CIP and EPCOR's proposal in the EB-2016-0137/0138/0139.

Responses:

A copy of EPCOR's CIP has been filed with this IR. EPCOR notes that its CIP is its proposal for EB-2016-0137/0138/0139.

EPCOR

2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

October 16, 2017

VIA RESS AND COURIER

Attention: Registrar
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: EPCOR Southern Bruce Gas Inc.
South Bruce Expansion Applications EB-2016-0137 | EB-2016-0138 | EB-2016-0139

Please find enclosed EPCOR Southern Bruce Gas Inc.'s Common Infrastructure Proposal to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with natural gas distribution services.

Should you have any questions, please do not hesitate to contact the undersigned.

Sincerely,

[Original signed by]

Bruce Brandell
Director, Corporate Development
EPCOR Commercial Services Inc.
bbrandell@epcor.com
(780) 412-3720

ELECTRONIC COPY

EPCOR

SOUTHERN BRUCE COMMON INFRASTRUCTURE PLAN APPLICATION

EB-2016-0137 /EB-2016-0138 / EB-2016-0139

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with Natural Gas Distribution Services

October 16, 2017

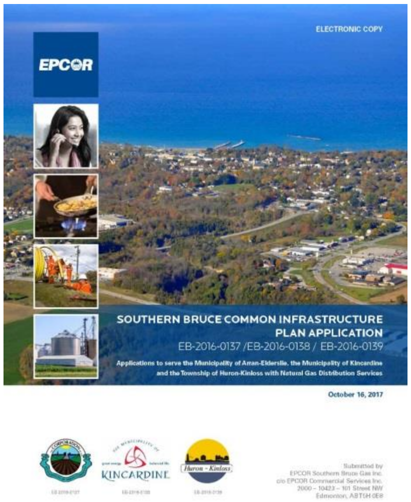
The Corporation of the Municipality of Arran-Elderslie
EB-2016-0137

The Municipality of Kincardine — great energy. balanced life.
EB-2016-0138

Huron - Kinloss
EB-2016-0139

Submitted by
EPCOR Southern Bruce Gas Inc.
c/o EPCOR Commercial Services Inc.
2000 – 10423 – 101 Street NW
Edmonton, AB T5H 0E8

TAB 1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EPCOR

SOUTHERN BRUCE COMMON INFRASTRUCTURE PLAN APPLICATION

EB-2016-0137 /EB-2016-0138 / EB-2016-0139

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with Natural Gas Distribution Services

October 16, 2017

Submitted by
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c/o EPCOR Commercial Services Inc.
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Edmonton, AB T5H 0E8

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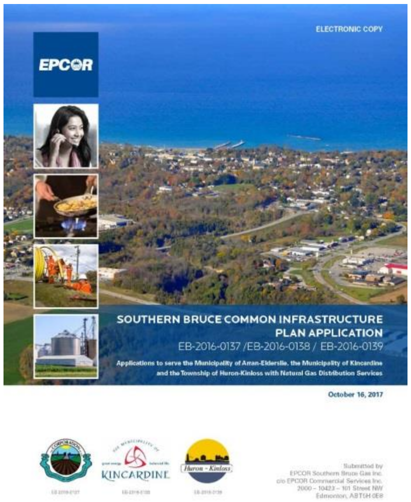


TAB 2

Executive Summary

Executive Summary

1. EPCOR is pleased to have this opportunity to present to the Ontario Energy Board (OEB) its proposal for introducing its unique and innovative approach to bringing natural gas infrastructure to the communities in Southern Bruce, one of the many communities in Ontario that can benefit from the EPCOR approach. This OEB process is precedent setting in several ways.

2. First and foremost, the OEB is relying on a competitive process to maximize value for future Southern Bruce customers, without depending on explicit or implicit subsidies from existing natural gas customers in the Province. The new service area will have self-supporting rates that benefit from Ontario's natural gas infrastructure program. EPCOR proposes to achieve this objective through a stand-alone natural gas utility.

3. OEB's Renewed Regulatory Framework for Electricity Distributors and its Handbook for Utility Rate Applications, proposes increased customer focus and a shift from cost recovery to long term value for money. EPCOR through this submission proposes such an approach to extend to gas distribution in Ontario.

4. By creating a new stand-alone utility, EPCOR is able to bring a number of unique benefits to nine Southern Bruce Communities (Chesley, Paisley, Inverhuron, Tiverton, Kincardine, Lurgan Beach, Point Clark, Ripley, and Lucknow) as well as the Bruce Energy Centre. These communities awarded EPCOR franchise agreements through their competitive process as the first step in their partnership with EPCOR to bring the following benefits to their region:

   - A natural gas distribution system that would be undertaken by an experienced utility operator in EPCOR, who is like minded in its approach and committed to working closely with the communities it serves.
   - The economic development opportunities that will ensue from having competitive natural gas service to attract the anticipated commercial and residential development as a result of the planned refurbishment of the Bruce Power nuclear facilities.
   - A commitment to seek out synergies that will reduce the cost of not only the local natural gas distribution system but also to assist in the development of other infrastructure projects that are important to the communities. These other infrastructure opportunities include high speed internet and the provision of water and wastewater services to the region's expanding business and residential development.

5. EPCOR believes that endorsing the selection that is supported by the local communities based on a broader spectrum of benefits EPCOR offers, the OEB will encourage all utilities to continually seek innovative strategies for managing costs to achieve lower long term rates for its customers. EPCOR's objective is not simply to ensure that the recoverable costs from rates are prudently incurred; but also to investigate and pursue all available strategies to ensure that costs borne by ratepayers are the lowest prudently possible. Our proposed value-added synergies are central to this goal. We do this by leveraging the vast knowledge and experience that we have gained in other utility operations including electrical, natural gas, water and waste water treatment and sanitary collection in both Canada and the United States. By pursuing infrastructure synergies, we bring additional benefits to the communities through reduced costs,

and improved service of other infrastructure projects. EPCOR believes that the broader public interest can be best served by thinking 'outside the box' by aggressively pursuing synergies with other non-gas utility operations. By introducing this approach to doing business in Ontario, EPCOR believes it can lead by example to positively influence the approach taken in future competitive infrastructure projects in Ontario.

6. This OEB process also promises to be precedent setting by shifting some of the traditional utility risks from ratepayers to investors. Specifically, the CIP process has limited customer risk through a 10 year rate stabilization period during which any operating cost overruns, if incurred, cannot be recovered from customers. The investor also takes the capital cost risk for the initial capital invested even beyond the 10 year rate stability period. It would be unfortunate for customers if the competitive factors that produced the current CIP were not to persist. Furthermore, this CIP process has resulted in investors taking additional risk that go beyond what has been traditionally required of utilities in the province. Table 1 below provides a summary of these risks and their allocation:

Table 1: CIP Application Utility Risk

Risks	Traditionally	Under this CIP	EPCOR at LTC
Initial Capital Cost	Ratepayer	Utility Shareholder	Utility Shareholder
O&M Costs – 10 years	Ratepayer	Utility Shareholder	Utility Shareholder
Target Connections – 10 years	Ratepayer	Utility Shareholder	Utility Shareholder
Target Volumes – 10 years	Ratepayer	Utility Shareholder	Utility Shareholder
Commercial Upside Post CIP – Additional Volumes, New Synergies, etc.	Not Defined	Not Defined	Passed to the Ratepayer
Projected "Customer Years" – 10 years	Ratepayer	Utility Shareholder	Utility Shareholder
Return on Equity	Ratepayer	Utility Shareholder	Utility Shareholder

About EPCOR

7. EPCOR Utilities Inc. owns and operates electrical transmission and distribution networks, and natural gas distribution networks, water and wastewater treatment facilities, sanitary and storm water systems and networks in Canada and the United States. EPCOR manages over $6.0 billion in assets and an annual capital program of approximately $530 million. As at December 31, 2016, EPCOR employed 2,710 full-time, part-time, temporary and casual employees. The recent transfer of the City of Edmonton's sanitary and storm water utilities to EPCOR have added another 700 employees. In fiscal 2016, EPCOR's consolidated revenue was $1.946 billion and its consolidated operating income was $309 million. Additionally, EPCOR's acquisition of the natural gas distribution assets of Natural Resource Gas Limited (NRG) received regulatory approval from the Ontario Energy Board in August 2017. Closing of this transaction is expected by end of October 2017.

8. For this project, EPCOR's team consists of its newly acquired NRG management team who has already provided guidance on this project, AECON Utilities as design-construction partner, and Stantec Consulting Ltd. who are close to completing the Project Environmental Report (ER).

CIP Common Parameters

9. The parties have agreed to service the communities of Chesley, Inverhuron, Paisley, Tiverton, Kincardine, Lucknow, Lurgan Beach, Point Clark, Ripley, and Bruce Energy Centre Industrial Park (Project), all to be serviced within two years from the commencement of construction. Volume forecasts for mass markets have relied on common average use consumption levels. Large commercial or industrial customer volumes have been individually forecast separately by Union and EPCOR.

10. The utility capital structure, tax, depreciation, interest during construction, and inflation rates are as outlined in the Union/EPCOR Letter to the Board of Oct 2, 2017. No Z-Factor events in the Revenue Requirements are included. EPCOR commits to meet or exceed the Service Quality Requirements (SQR) in accordance with Board's Gas Distribution Access Rule (GDAR) dated January 1, 2017.

CIP Common Exclusion Parameters

11. As per OEB guidance, the grants, contributions, aids to construction, demand side management programs, cap and trade costs, gas commodity costs, and upstream reinforcement costs, have been excluded from the revenue requirement calculations.

12. While the costs of raising debt and equity to finance the Southern Bruce Project have been incorporated into the overall revenue requirement, the Board has confirmed that the cost of debt and the return on equity are considered competitive elements, and therefore have not been disclosed.

CIP EPCOR Proposed Parameters

13. Within the proposed geographical target market of Arran-Elderslie, Kincardine, and Huron-Kinloss, EPCOR has estimated the total available market to be 8,739 customers. EPCOR forecasts attaching a total of 5,278 customers over the 10-year rate stability period based on a conversation rate of 60% for residential customers and 65% commercial customers. This is supported by formal survey results for residents and extensive face to face meetings with commercial customers and augmented with the results of a commercial survey.

14. Details of the infrastructure proposed, including routing, engineering, material specifications, construction schedule, environmental considerations have all been provided herein.

15. EPCOR has applied the utility principles of fully allocated costs as set out in the August 22, 2017 Decision on Preliminary Issues and Procedural Order No. 8, to preventing any cross-subsidization of new expansion customers by current ratepayers. EPCOR has included the royalty payments proposed to be made to the municipalities in the overall revenue requirement.

16. The annual revenue requirements commencing 2019 through 2028 are provided hereunder:

Table 2: Annual Revenue Requirement (2019 – 2028)

Year									
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
1,332,492	4,388,984	6,155,922	7,534,172	8,488,867	9,122,050	9,406,087	9,567,338	9,722,807	9,864,542

- The net present value of revenue requirement over the 2019-2028 period is $59,072,317.
- The cumulative revenue requirement over the 2019-2028 period is $75,583,261.

CIP Revenue Requirement and Customer Comparison Criteria

17. The following are EPCOR's forecasted revenue requirement and customer volume parameters:

Table 3: Forecasted Comparison Parameters

Comparison Parameter	Forecast
EPCOR Planned Cost per m^3 for the 10 year 2019-2028 period	0.1766 $/ m^3
EPCOR Planned No. of Customer Years over the 10 year 2019-2028 period	42,569
EPCOR Planned Cumulative Volume over the 10 year 2019-2028 period	428,035,564

18. The above forecasted comparison parameters do not take into account several additional community based value-added initiatives which EPCOR is currently pursuing and may come into fruition before filing the necessary Leave to Construct (LTC) application. If selected by the Board as the successful proponent, it is EPCOR's intention to add the benefits of those synergies and volume to its final rate application to pass on these benefits to the ratepayers during the 10-year rate stability period, as summarized below.

Other Value-Added Factors

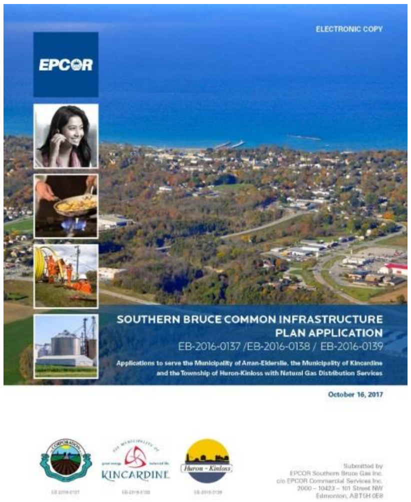
19. EPCOR, as the communities' preferred franchisee has collaborated not only towards developing its natural gas Project, but also providing significant other value-added initiatives that will directly benefit the Project as well as taxpayers in the communities. These other value-added initiatives, which are more fully detailed in the submission, include the following:

    - A multi-utility partnership with the respective communities to realize further efficiencies, introduce synergies, and introduce economies of scale, all of which will help with the overall economic development of the communities as well as the lower rates for the respective ratepayers.
    - Two synergistic initiatives that this early partnership between the communities and EPCOR proposes the co-construction of a water pipeline and fibre optics network during the construction of the natural gas lines into the communities.

- There is an opportunity to accelerate the construction schedule since EPCOR has completed a large percentage of the work for the Environmental Report (ER) initiated in anticipation of being awarded the Franchise by the OEB.
- A proposed future EPCOR-Municipal partnership that contemplates multi-utility level operational efficiencies by way of service level agreements (“SLA”) or formal alliance agreements resulting in additional synergies of mutual benefit for EPCOR and the respective municipalities. EPCOR and the Southern Bruce municipalities are also exploring additional initiatives for multi-utility servicing of business parks in the communities to attract new business by providing the multi-utility services to these lands on a fast track basis to benefit the gas utility as well as the municipalities.
- The natural gas facility construction will also result in the development of a five kilometre bike path to the community.
- Also under discussion is EPCOR undertaking the fibre optics project co-construction under a Design-Build-Operate and Finance Agreement that the municipality, through its wholly-owned telecommunications company finds of significant value.
- Finally, one immediate potential benefit that would result in additional cost savings for all ratepayers involves EPCOR working with an agro-business to develop a CHP facility in a Business Park to help expand a revitalized greenhouse enterprise, if finalized before the LTC application. EPCOR has used its multi-utility experience to propose a CHP facility as a cost-effective solution to overcome a local power transmission constraint and provide heating and cooling to further improve the economic benefits. Based on current estimates this could translate into savings to all ratepayers of up to 3-8% during the rate stability period further improving the economic success of the Project and lower the cost of the gas supply for the community.

20. As noted previously, EPCOR’s strong relationship with the communities and its local government leadership has been ongoing and strengthened over the last 24-30 months. During this time, the parties have worked diligently as partners to develop new and creative ways to enhance this Project and explore how EPCOR, with its broad integrated utilities background and financial wherewithal, may bring about other economic development initiatives to help the municipalities and in the process, improve the natural gas project benefits to its ratepayers. Both the municipalities leadership, and EPCOR, believe that in the long term, the Project success will largely depend on finding creative synergies by way of economies of scale under a well aligned utility platform. This alignment and resulting benefits have already been identified in the 24 short months through construction synergies and other value-added benefits that now remain to be realized.

Figure 1: EPCOR Kincardine Customer Care Centre Opening – Ribbon Cutting



TAB 3

Applicant Background & Contact

1. Applicant Background & Contact

Contact Information:

The Applicant

Name:	EPCOR Southern Bruce Gas Inc.
Address:	c/o EPCOR Commercial Services Inc. 2000 – 10423 – 101 Street NW Edmonton, AB T5H 0E8
Telephone:	(780) 412-3720
Email:	bbrandell@epcor.com
Fax:	(780) 441-7118

Primary Representative for the Applicant

Name:	Bruce Brandell
Address:	2000 – 10423 – 101 Street NW Edmonton, AB T5H 0E8
Telephone:	(780) 412-3720
Email:	bbrandell@epcor.com
Fax:	(780) 441-7118

Legal Representative(s)

Name:	Britt Tan
Address:	2000 – 10423 – 101 Street NW Edmonton, AB T5H 0E8
Telephone:	(780) 412-3998
Email:	btan@epcor.com
Fax:	(780) 441-7118

Name:	Richard King
Company:	Osler, Hoskin & Harcourt LLP
Address:	100 King Street W One First Canadian Place Suite 6200 Toronto, ON M5X 1B8
Telephone:	(416) 862-6626
Email:	rking@osler.com
Fax:	(416) 862-6666

Affiliates

1. For the purposes of the Affiliate Relationship Code for Gas Utilities, all of the subsidiaries of EPCOR Utilities Inc. ("EUI") are deemed to be affiliates of EPCOR Southern Bruce Gas Inc., as EPCOR Southern Bruce Gas Inc. is a direct subsidiary of EUI. Following the closing of EPCOR Natural Gas Limited Partnership's purchase of the natural gas distribution system of Natural Resource Gas Limited expected by the end of October 2017, EPCOR Natural Gas Limited Partnership will be operating a gas distribution system in Aylmer, Ontario. Other than EPCOR Natural Gas Limited Partnership and its general partner and limited partner, no other EUI subsidiaries operate businesses in Ontario. Please refer to Figure 2 for a simplified corporate chart of EUI depicting EUI's material subsidiaries and subsidiaries related to Ontario.

Background on Applicant

2. EPCOR Southern Bruce Gas Inc. is a corporation incorporated under the laws of the Province of Ontario and is an indirect wholly owned subsidiary of EUI which is a corporation incorporated under the laws of the Province of Alberta, and wholly owned by the City of Edmonton. EUI's head office is in the City of Edmonton. Figure 2 below outlines the corporate structure of EUI.

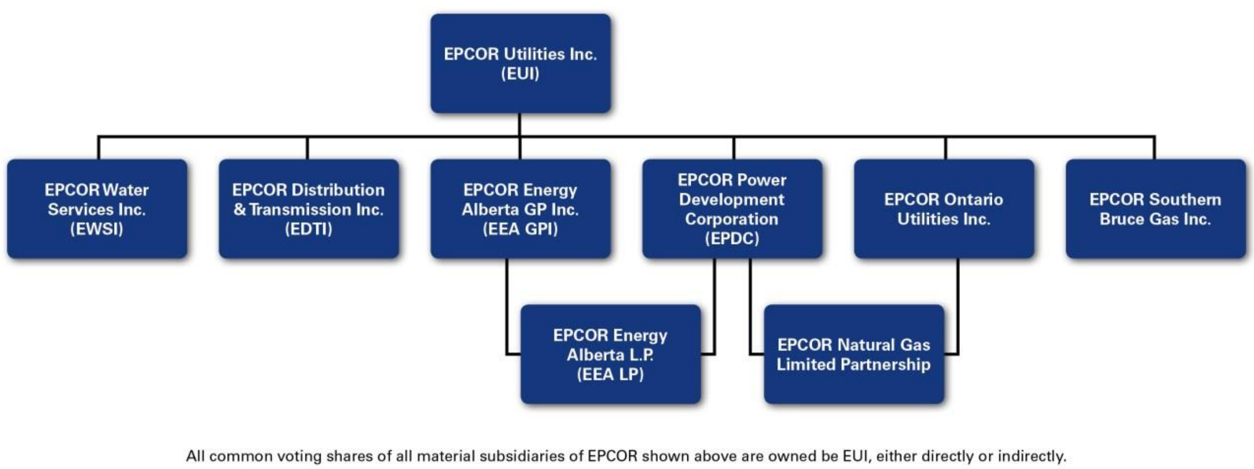


Figure 2: EPCOR Utilities Inc. Corporate Structure

3. EUI, through wholly-owned subsidiaries (collectively, "EPCOR"), builds, owns and operates electrical transmission and distribution networks, natural gas distribution networks, water and wastewater treatment facilities, and sanitary and stormwater systems and networks in Canada and the United States. Figure 3 highlights the locations of major EPCOR operations.

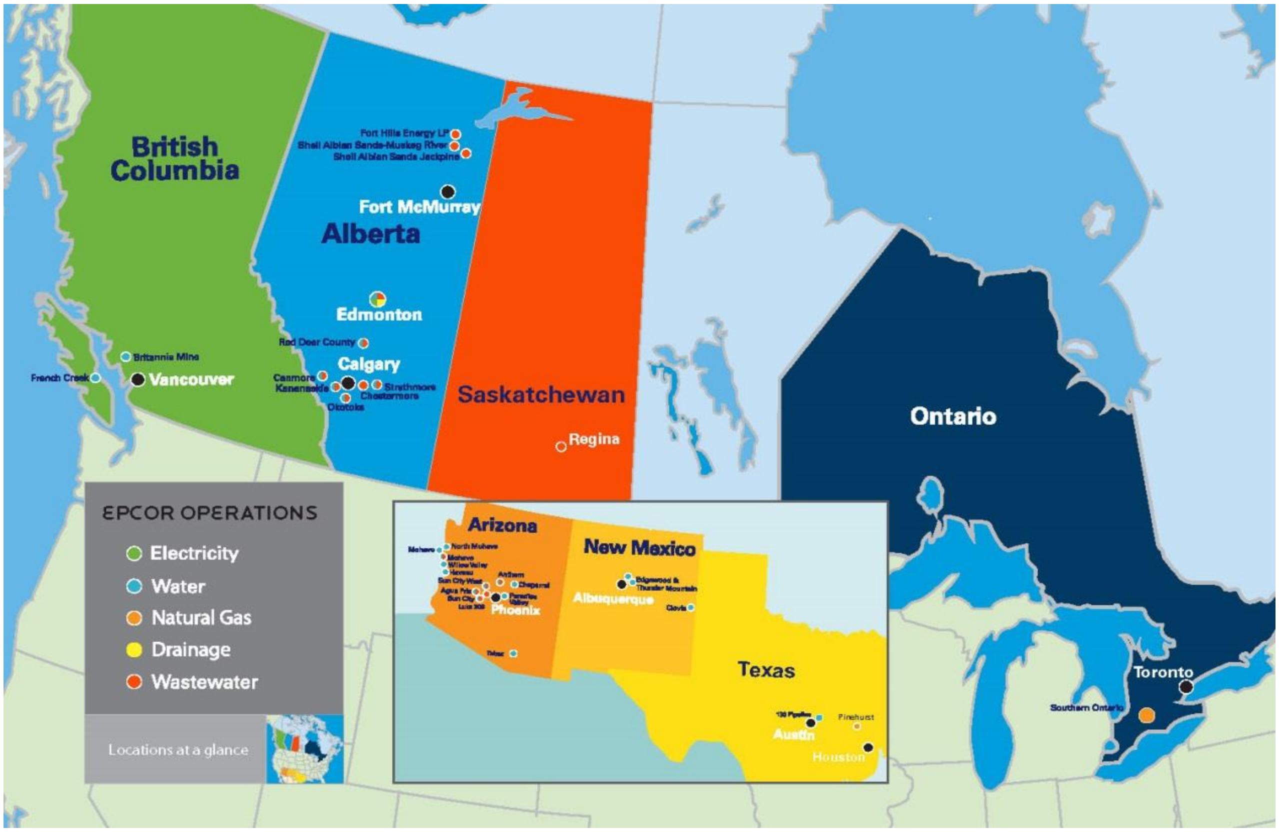


Figure 3: EPCOR Operations

4. As a multi-utility company, EPCOR brings a unique perspective to the provision of utility services. This value has been uniquely demonstrated in the competitive market for electricity services in Alberta. EPCOR feels that in Ontario the provision of natural gas services could benefit from a multi-utility approach that provides multiple utilities to a customer within a geographic region. EPCOR's multi-utility offering and its municipal history were a critical factor in being selected as the preferred franchisee in Southern Bruce.

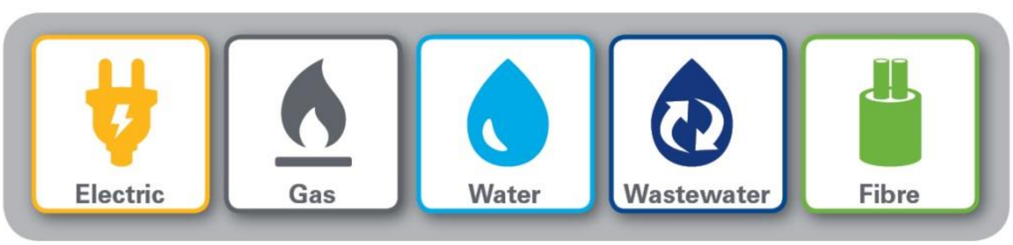


Figure 4: EPCOR Multi-Utility Scope of Services

5. EPCOR's electric distribution and transmission businesses own and operate high voltage substations and transmission lines and cables that are primarily situated within and around Edmonton and form part of the Alberta Interconnected Electric System ("AIES") power grid. Through these facilities, EPCOR provides transmission services to the Alberta Electric System Operator ("AESO"), the independent not-for-profit entity that is charged with, among other things, ensuring the efficient operation and expansion of the Alberta transmission grid. In 2015,

EPCOR distributed approximately 13% of Alberta's provincial energy consumption to approximately 343,000 residential and 36,000 commercial and industrial customer sites in Edmonton.

6. EPCOR's energy services business procures electricity for its Regulated Rate Option and default supply customers in Alberta and provides customer care and billing services to its customers, and certain customer care and billing services to affiliates and third parties. The energy services business also sells electricity and natural gas to Alberta consumers under competitive contracts through its Encor brand. EPCOR provides billing and customer care services to approximately 640,000 energy and natural gas customer sites and 265,000 water customer sites in Alberta.

7. EPCOR's water business provides water purification, water distribution, wastewater treatment, sanitary and stormwater systems and related management services within the City of Edmonton and several other communities in Western Canada and the Southwestern United States, and provides similar services and water and wastewater plant financing and construction services to industrial customers in Western Canada. In Edmonton and surrounding areas, EPCOR services a population of over 800,000 and delivers bulk water to over 67 communities and counties. In addition, EPCOR USA provides water purification and distribution and wastewater collection and treatment services in the southwestern United States to more than 350,000 people in Arizona and New Mexico. It also delivers wholesale water service to municipalities in the Austin metropolitan area.

8. In September 2017, the City of Edmonton transferred its sanitary and stormwater system to EPCOR. This system contains pipes, tunnels, pump stations and stormwater management facilities that make up the sanitary and stormwater network in the City of Edmonton. Wastewater from the system is transported to EPCOR's Gold Bar Wastewater Treatment Plant.

9. EPCOR's acquisition of the natural gas distribution assets of Natural Resource Gas Limited (NRG) received regulatory approval from the Ontario Energy Board in August 2017. Closing of this transaction is expected by the end of October 2017. Once complete, EPCOR will distribute natural gas to over 8,700 residential, commercial and industrial customers in Elgin, Middlesex, Oxford and Norfolk counties in southwestern Ontario. EPCOR also owns and operates a natural gas utility that provides service to approximately 4,300 connections and wholesale natural gas transmission service to local distribution utilities near Houston, Texas.

10. EPCOR is a public issuer of debt with current credit ratings of A- stable (S&P) and A (low) stable (DBRS). In fiscal 2016, EPCOR's consolidated revenue was $1.946 billion and its consolidated operating income was $379 million. Presently EPCOR has credit facilities totaling $575 million of which $375 million is available for borrowing. EPCOR also has access to long-term debt through the Canadian public debt market where it has an existing $1-billion, short form base shelf prospectus.

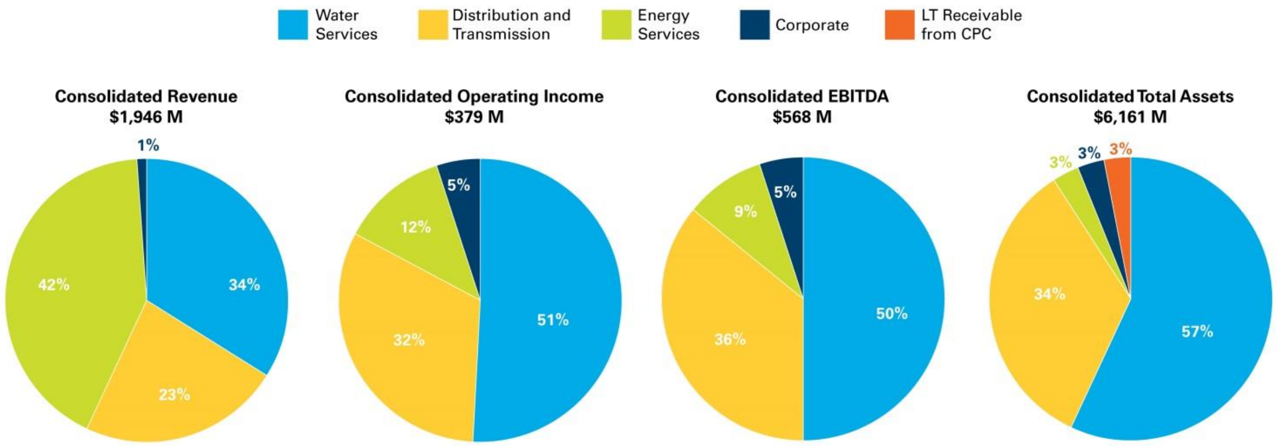


Figure 5: EPCOR's 2016 Financial Overview

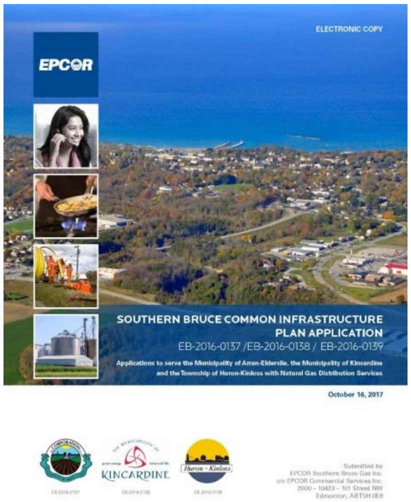
11. In its major business units (electricity distribution and transmission; water and wastewater; natural gas and energy services), EPCOR's customers number in the hundreds of thousands. EPCOR and its predecessors, through their subsidiaries, have provided reliable utility service for over 120 years, consistently meeting and exceeding service quality metrics in the areas served. Details of EPCOR's corporate profile, major operations and corporate finances are provided in EPCOR Utilities Inc.'s 2016 Annual Information Form, a copy of which is attached as Schedule F.

12. As at December 31, 2016, EPCOR employed 2,710 full-time, part-time, temporary and casual employees. The recent transfer of the City of Edmonton's sanitary and stormwater system to EPCOR added approximately 700 employees. Further, EPCOR has a strong working relationship with its five labour unions; four based in Alberta and one in Saskatchewan. As of December 31, 2016, the five labour unions represented over 1,772 EPCOR employees. For more than a decade, EPCOR has been on multiple lists ranking best employers and corporate citizens. These include Canada's Top Employers for Young People, Alberta's Top 70 Employers, Best Place to Work (EPCOR Water USA), Government of Alberta Envirovista Program and Public-Private Partnership (P3) awards, and the Best 50 Corporate Citizens (2014). EPCOR employees volunteer thousands of hours of their time each year in their communities both on their own as well as through EPCOR organized initiatives with its Community Partners. EPCOR further supports its employee community volunteer efforts with Helping Hands Grants to the charitable organizations that its employees are directly involved with. EPCOR and its employees also raise funds through an annual United Way campaign and EPCOR further supports the communities it works in through its education focused corporate giving program.

13. EPCOR is subject to federal, provincial, state and municipal operational, rate-setting, environmental and safety laws, regulations and guidelines concerning its businesses. EPCOR has developed positive, ongoing working relationships with a number of regulators and agencies including the Alberta Utilities Commission (AUC), the AESO, the BC Water Comptroller, the Arizona Corporate Commissions and the New Mexico Public Regulation Commission. EPCOR also works closely with a number of government health and safety agencies including Health Canada, Alberta Environment and Parks Alberta, multiple Occupation Health and Safety agencies, Water Security Agency (Saskatchewan), and Work Safe BC. Many of EPCOR's facilities are ISO 14001 and OHSAS 18001 certified.

14. EPCOR manages over $6.0 billion in assets and an annual capital program of approximately $530 million. EPCOR and its design-build partners have also successfully designed, built, owned and operated 15 water/wastewater projects in Western Canada, outside of Edmonton. This achievement is the direct result of EPCOR's ability to evaluate projects efficiently and accurately, and to add value to benefit its clients over the entire project life cycle. EPCOR's construction experience includes installing systems in geographies and terrains with complex geological conditions including rocky formations in British Columbia to desert sands of Arizona. EPCOR has experience with aerial as well as underground installations of linear assets, from extreme hot to extreme cold seasonal conditions and specific experience with horizontal directional drilling installations along highways and under rivers, consistently demonstrating sensitivity towards the environment. A recent installation included crossing under multiple water ways within an environmentally sensitive provincial park. EPCOR also has experience in constructing linear infrastructure in mature urban areas where it has demonstrated social sensitivity with respect to ongoing access for homeowners and restoration of property to original or better condition.

15. EPCOR employs program and project management methodologies based on industry best practices, such as from the Project Management Institute. These program elements include Defining, Planning, Executing, Monitoring and Controlling, and Closing. Project scope, schedule, resources, budget, and risk are addressed in all of these elements. Key aspects that have driven EPCOR's project management success include: rigorous executive oversight; and an internal independent Project Management Office that sets standards for and then monitors project progress, creates standard templates for project scoping and reporting to ensure consistency, undertakes ongoing risk assessment and mitigation, and holds regular lessons learned workshops to incorporate continuous improvement into EPCOR's processes. As a utility operator, EPCOR carefully considers factors such as operability, maintainability, and life-cycle asset management costs in carrying out each project. All projects focus on safety as a priority in the design, construction and maintenance of all capital projects, with safety performance being held to the highest standard.



TAB 4

CIP Common Parameters

2. CIP Common Parameters

Common Assumptions Agreed by the Parties

Communities to be Served

1. As part of the Southern Bruce Natural Gas Project, EPCOR agrees to provide natural gas service to the communities of Chesley, Paisley, Inverhuron, Tiverton, Kincardine, Lurgan Beach, Point Clark, Ripley, Lucknow and the Bruce Energy Centre. The proposed infrastructure to service these communities is illustrated in Figure 7 and Schedule B.

Rate Stability Period

2. The Board indicated in its Decision on Preliminary Issues and Procedural Order No. 8 Dated August 22, 2017 that:

   "For the purpose of structuring a common platform for selection purposes, the OEB finds that proponents should price their revenue requirement proposals based on the assumption that there will be no rate adjustments during the 10-year rate stability period, other than the availability of Z-factor relief for certain events that fall within the OEB's policy".

3. EPCOR accepts this 10-year rate stability period for the delivery rates. The revenue requirement has been prepared on this basis. EPCOR has incorporated the annual inflation adjustment of 1.27% as referenced in Schedule C in calculating its revenue requirement.

Forecast Horizon

4. EPCOR has used a 10-year forecast period for customer attachments and volume forecasts and in preparing the three comparison metrics as set out in the OEB Staff Progress Update dated July 20, 2017:

   - **$/m^3** –the sum of total (gross) annual revenue requirement for 10 years divided by the total volumes for 10 years
   - **Number of customer years** – the cumulative number of customers connected over the 10 year rate stability period multiplied by the number of years each customer is connected
   - **Cumulative volume (m3)** – the cumulative volume of throughput per year, over the ten-year rate stability period. This metric would be calculated in a similar manner to the second criteria, but based on the volume consumed by the customers to better depict the various customer classes and their demand. Credit for volumes from new customer additions in a specific year are based on connection to the system in the middle of the year, with the exception of large industrial and commercial customers for whom a specific connection period can be determined by the proponent.

Customer Consumption Levels

5. EPCOR and Union have worked cooperatively to reach agreement on the average annual consumption levels for the mass markets. Schedule C is a copy of the letter sent to the Board dated October 2, 2017 outlining the categories of mass markets and the respective average consumption for each category of customer. Fifty percent of these consumption levels have been used as the estimated consumption level for the customer's first year of service. As directed by the Board, EPCOR has developed its own volumetric estimates for large industrial and commercial customers. As agreed with Union, these large commercial customers include large poultry farms and grain dryers as these loads could be route dependent. These consumption levels have been used in developing the comparative metrics.

6. Several industrial customers are expected to enter into long term contracts for capacity. Annual volumes for these customers have been based on the capacity under contract.

Community Service Period

7. EPCOR has agreed to develop the overall infrastructure necessary to provide service to each of the above listed communities over a two year period.

Depreciation Rates

8. EPCOR has agreed to use Union's Board approved depreciation rates and confirms that these rates have been incorporated in its submission. These rates can be found in Schedule C.

Capital Structure

9. EPCOR's CIP revenue requirement has been based on Union's approved deemed debt/equity ratio of 64% / 36%.

Interest During Construction (IDC)

10. EPCOR confirms that it has used the Board's fourth quarter 2017 Construction Work in Progress (CWIP) rate of 2.99% as outlined in Schedule C.

Inflation Costs

11. As outlined in Schedule C, EPCOR has used an inflation rate of 1.27% in calculating its annual revenue requirement. This is the most recent four quarter average annual inflation rate as determined from GDP IPI FDD, which is reported for the second quarter of 2017.

Z-Factor Relief

12. EPCOR has not included any Z-Factor events in its revenue requirement, but acknowledges that during the 10-year rate stability period Z-Factor relief may be available for certain OEB approved Z-Factor events during this period.

Tax Rates

13. A corporate income tax rate of 26.5% has been used in developing EPCOR's revenue requirement.

Service Levels

14. EPCOR acknowledges that the Board's Gas Distribution Access Rule (GDAR) dated January 1, 2017, sets out: certain rules governing the conditions of access to gas distribution services provided by a gas distributor, rules governing the conduct of a gas distributor as such conduct relates to a gas vendor, and certain minimum Service Quality Requirements (SQR) for natural gas distributors.

15. EPCOR confirms that it will comply with GDAR including, but not limited to, the minimum SQRs established by the Board as set out in Section 7. EPCOR is in the process of acquiring the assets of Natural Resource Gas Ltd. (NRG) pursuant to the Board's August 3, 2017 decision in EB-2016-0351. Table 4 illustrated below, is an excerpt from the Board's "2016 Yearbook of Natural Gas Distributors" dated August 17, 2017 outlining the major Ontario natural gas distributors' 2016 SQR performance results. EPCOR notes that NRG has not only met or exceeded the Board's SQRs, but in most cases exceeded the SQR metrics of the other major Ontario natural gas utilities. EPCOR will employ the best practices of NRG in the operation of Southern Bruce.

Table 4: 2016 Service Quality Requirements Performance Results

Service Quality Requirements	Enbridge	Union	NRG
Call Answering Service Level (OEB Minimum Standard: 75%)	82.40%	80.10%	98.50%
Number of Calls Abandon Rate (OEB Standard: not exceed 10%)	1.80%	3.60%	1.50%
Meter Reading Performance (OEB Standard: not exceed 0.5%)	0.40%	0.10%	0.00%
Appointments Met within Designated Time Period (OEB Minimum Standard: 85%)	94.80%	98.90%	99.30%
Time to Reschedule Missed Appointments (OEB Standard: 100%)	94.20%	99.80%	100.00%
Emergency Calls Responded within One Hour (OEB Minimum Standard: 90%)	96.10%	98.80%	93.20%
Number of Days to Provide a Written Response (OEB Minimum Standard: 80%)	95.50%	100.00%	100.00%
Number of Days to Reconnect a Customer (OEB Minimum Standard: 85%)	93.70%	86.20%	91.70%

Common Exclusions Agreed by the Parties

Grants, Contributions and Aids to Construction

16. EPCOR has prepared its revenue requirement and excluded any grants from the Ontario Ministry of Infrastructure, contributions from municipalities related to property tax rebates, and any aids to construction.

Demand Side Management (DSM Programs)

17. EPCOR has not included any costs associated with DSM programs in its revenue requirement.

Cap and Trade Costs

18. No costs associated with complying with the Board's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities dated September 26, 2016, have been incorporated in the preparation of the revenue requirement.

Gas Commodity Costs

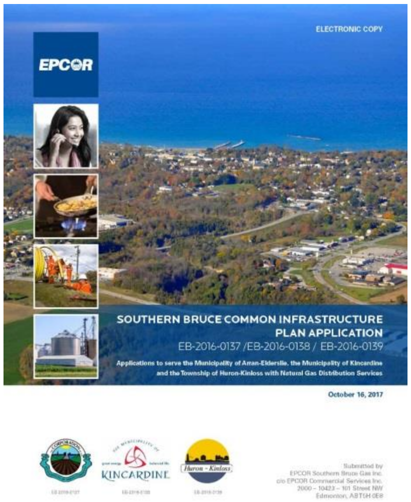
19. No gas commodity costs have been included in the revenue requirement.

Upstream Reinforcement Costs

20. Consistent with the Board's direction in the Decision on Preliminary Issues and Procedural Order No. 8 Dated August 22, 2017, EPCOR has excluded any costs associated with the upstream reinforcement of the Union Gas system that may be required to deliver gas to the Dornoch meter station. Similarly, ongoing upstream transportation charges have been excluded from the revenue requirement.

Cost of Debt & Return on Equity

21. While the costs of raising debt and equity to finance the Southern Bruce Project have been incorporated into the overall revenue requirement, the Board has confirmed that the cost of debt and the return on equity are considered competitive elements in the proponents CIP submissions. EPCOR therefore has not separately disclosed these inputs.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EPCOR

SOUTHERN BRUCE COMMON INFRASTRUCTURE PLAN APPLICATION

EB-2016-0137 /EB-2016-0138 / EB-2016-0139

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with Natural Gas Distribution Services

October 16, 2017

Submitted by
EPCOR Southern Bruce Gas Inc.
c/o EPCOR Commercial Services Inc.
2000 – 10423 – 101 Street NW
Edmonton, AB T5H 0E8

TAB 5

CIP EPCOR Proposed Parameters

3. CIP EPCOR Proposed Parameters

EPCOR Market Projections

1. Within the proposed geographical target market of Arran-Elderslie, Kincardine, and Huron-Kinloss, EPCOR has estimated the total available market to be 8,739 residential, commercial, industrial, and agricultural customers. EPCOR forecasts attaching a total of 5,278 customers over the 10-year rate stability period.

Customer Attachment Forecast

2. To assess the likelihood of residential customers converting to natural gas, EPCOR retained the firm of Innovative Research in July 2017 to conduct a residential telephone survey in the municipalities of Arran-Elderslie, Kincardine and Huron Kinloss slated to be served by EPCOR. As shown in Figure 6 this survey concluded that 58% of these residents "Definitely Would Convert" or "Would Likely Convert". Accordingly, EPCOR plans to implement a comprehensive marketing program to help customers assess the benefits of converting to natural gas and through these efforts, expectes to realize an overall 10-year residential conversion rate of 60%. This 60% target has therefore been applied as the overall 10-year capture rate for residential customers under the EPCOR plan. A total of 4,818 residential customers have been forecast to attach to the system over the 10-year rate stability period.

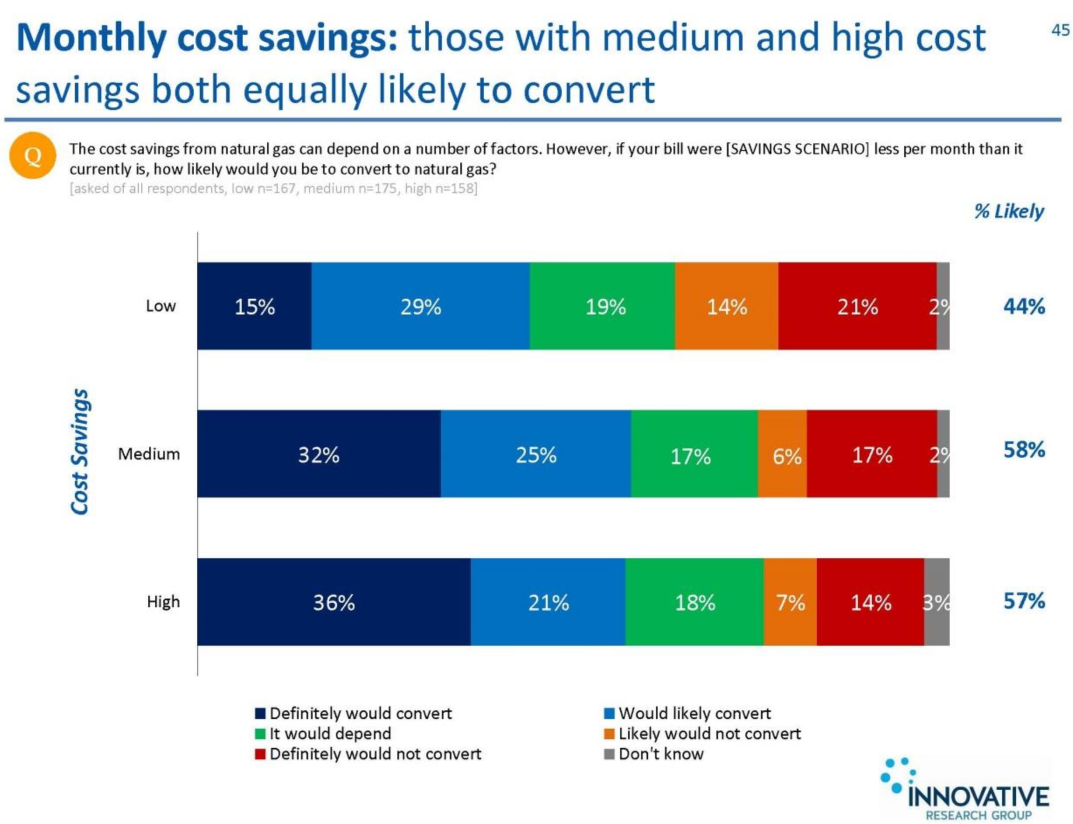


Figure 6: Customer Survey Results on Likelihood of Conversion

3. Total residential volumes have been derived by multiplying the average use per residential customer (for each of existing and new customers) assumptions agreed to between EPCOR and Union and illustrated in Schedule D, Table D2, by EPCOR's annual forecasted acquisition rate for each year over the 10-year rate stability period. The forecasted annual volumes for residential customers are illustrated in Schedule D, Table D3.

4. The municipalities of Arran-Elderslie, Kincardine and Huron-Kinloss previously retained Innovative Research (through their counsel BLG) to assess the feasibility of having these areas served by natural gas. That survey of commercial customers concluded that 65%[1] of this commercial customer sector would definitely or likely convert to natural gas if it were available. Based on recent discussions with customers, EPCOR has confidence in the 65% conversion rate which it finds a reasonable estimate of the commercial customers' conversion rate during the 10-year rate stability period, and has planned for this in its forecast. Commercial customers have been sub-divided by annual consumption levels as follows:

   - Small less than 15,000 m^3/year
   - Medium 15,000 - 50,000m^3/year
   - Large commercial customers 50,000 m^3/year

5. EPCOR forecasts that a total of 447 commercial customers will attach to the system over the 10-year rate stability period. The detailed annual forecast by commercial customer size is illustrated in Schedule D, Table D1.

6. EPCOR has worked closely with Union Gas to develop the average use per commercial customer by size. These average use estimates are illustrated in Schedule D, Table D2 and have been proposed as part of the common assumptions for this submission.

7. Total commercial volumes have been derived by applying the respective average use assumptions to the forecasted attachments. The annual volumes for commercial customers are illustrated in Schedule D, Table D3.

Large Contract Customer Volumes

8. EPCOR has also undertaken a more pro-active and consultative market assessment of the Industrial and large agriculture customer sector to assess their interest in converting to natural gas, and their natural gas requirements. EPCOR has therefore been able to individually forecast each customer requirements, consistent with the Board's direction[2].

9. EPCOR has aggregated industrial and large agricultural customer counts and volumes. This aggregation of customers was chosen for several reasons. Firstly, all customers' volumes are individually forecast as compared to other customers where there has been agreement with Union on their average use. Secondly, and more importantly, if there were further division of this category, there would be an insufficient number of customers in each category to maintain the confidentiality of each customer's respective volume. The Board has a long-standing practice of supporting the protection of commercially sensitive customer information. EPCOR

[1] Expansion of Natural Gas Distribution in Southern Bruce County. The Business Case October 6, 2014, page 28
[2] Decision on Preliminary Issues and Procedural Order 8 dated August 22, 2017 page 5

believes that this level of aggregation is the minimum level of aggregation required to preserve the confidentiality of all customers' volumes.

10. Within this category there are certain customers that are expected to enter into long term contractual commitments for distribution capacity. EPCOR anticipates that the contract rate will have a monthly demand charge for capacity similar in nature to the contractual rates charged by other gas utilities in the province, where all fixed costs are recovered in the demand charge. These customers have the flexibility of using the capacity at any time of the year. EPCOR has been working cooperatively with customers to look for ways to improve their overall energy efficiency through the application of a combined heat and power (CHP) facility where natural gas is used to meet both on-site heating needs as well as a portion of their power needs. The annual consumption levels of natural gas under a CHP facility are very different from serving a heating only load. EPCOR has been and continues to work very closely with this customer group to help evaluate the potential for CHP usage, however until the award of the franchise; neither the customers nor is EPCOR able to formalize any commitment. Because of the contract structure, the flexibility to use the capacity at any time of year, the payment for capacity reserved regardless of usage, as well as the uncertainty of customers' ultimate commitment to CHP, EPCOR has therefore applied the annual capacity expected to be under contract and it is this capacity that forms its volume forecast.

11. The total number of customers and the aggregate annual volumes can be found in Schedule D.

EPCOR Capital and Operating Plans

12. For this project, EPCOR's team consists of:

EPCOR	EPCOR's newly acquired management team from NRG, which have already been involved in this project.
AECON	AECON Utilities, one of Ontario's leading utility contractors, as design-construction partner.
Stantec	Stantec Consulting Ltd. for development of the Environmental Report (ER), which has completed over 200 ER's for natural gas projects in Ontario.

13. EPCOR proposes to develop a comprehensive natural gas distribution system to serve the communities of Chesley, Paisley, Inverhuron, Tiverton, Kincardine, Lurgan Beach, Point Clark, Ripley, Lucknow and the Bruce Energy Centre. EPCOR's distribution system will consist of two components – a larger diameter mainline that will be the backbone of the system and transport gas to each of the communities, and smaller diameter high density polyethylene (HDPE) distribution piping that will be constructed within each of the communities to directly serve homes and businesses.

14. The mainline will commence at Dornoch at an interconnection with Union Gas (Union) and will extend westerly from Dornoch to the Bruce Energy Centre, then extending southerly to serve Inverhuron, Kincardine Lurgan Beach and Point Clark. The mainline will then extend easterly to serve Ripley and Lucknow. Figure 7 illustrates the proposing routing of this mainline.

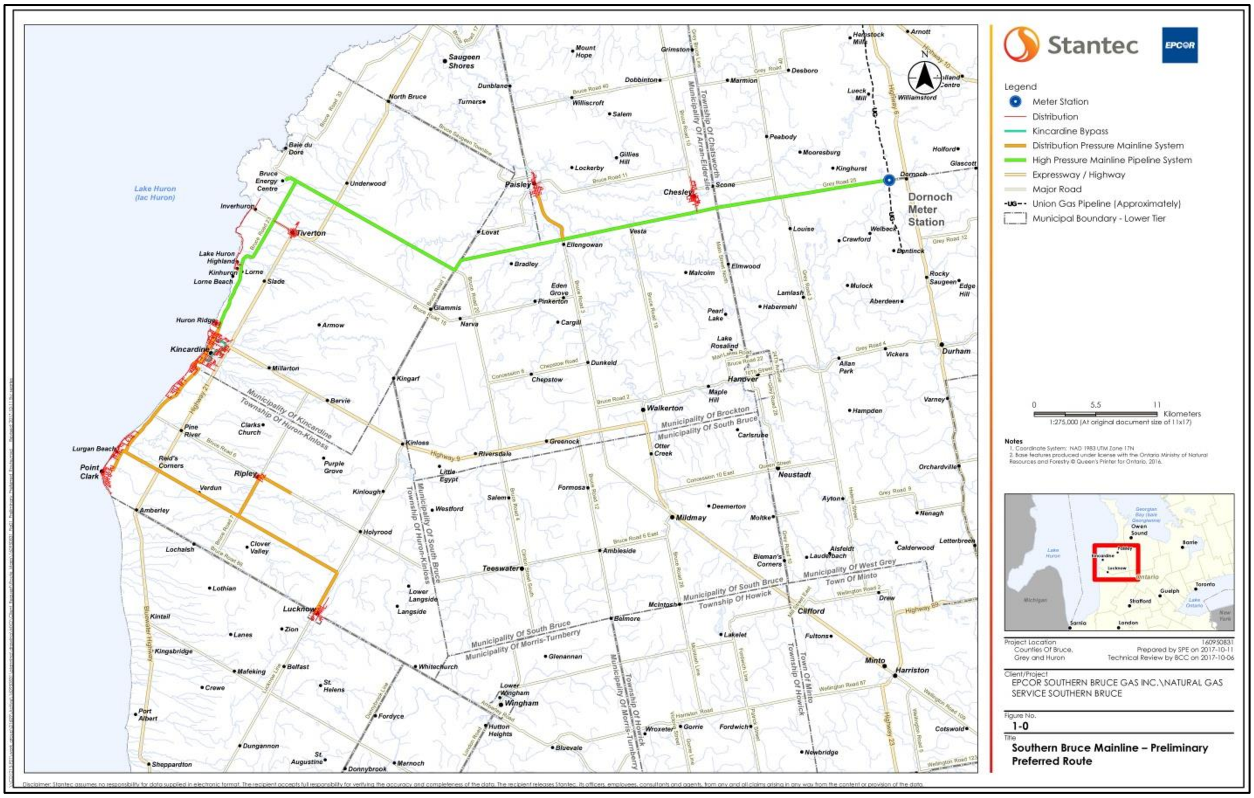


Figure 7: Southern Bruce Mainline – Preliminary Preferred Route

15. The mainline will be developed over two years and utilize two pressure systems. In 2019, the first year of the project, the mainline will be constructed from Dornoch to the south end of Kincardine. The portion of the mainline from Dornoch to the north end of Kincardine will consist of NPS 8 and NPS 6 steel pipeline. This steel line will be designed and tested for a maximum allowable operating pressure (MAOP) of 3447 kPa (500 psig), but is expected to operate at or below a pressure of 2068 kPa (300 psig). This pressure (2068 kPa) coincides with the proposed delivery pressure from Union. The higher design pressure will provide for longer term flexibility should a higher delivery pressure from Union be available in the future.

16. The remaining portion of the mainline through Kincardine is NPS 6 HDPE. The portion of this HDPE mainline from terminus of the steel line through Kincardine will also be developed in the first year of the project. EPCOR will install and operate a pressure regulating station at the junction of the steel system and the HDPE system to lower and control the pressure of the gas entering the HDPE system. This pressure reducing station will be situated in the north end of Kincardine. The balance of the NPS 6 HDPE mainline from the south end of Kincardine to Lucknow will be developed in the second year of the project commencing in early 2020.

17. The distribution systems within each of the communities serviced will be constructed using smaller diameter HDPE pipe. The MAOP of these HDPE systems will be 681 kPa (125 psig). The distribution system in Kincardine, Tiverton and Inverhuron will be constructed in 2019, with

the remaining communities of Chesley, Paisley, Lurgan Beach, Point Clark, Ripley and Lucknow constructed in 2020.

18. For those communities, such as Chesley, Paisley, Inverhuron and Tiverton, that are serviced off the higher-pressure steel mainline system, a pressure reducing station will be installed to lower the operating pressure of the gas prior to entering into the smaller diameter HDPE distribution.

19. For those communities south and east of Kincardine (Lurgan Beach, Point Clark, Ripley and Lucknow), the smaller diameter HDPE systems will be fed off the southern NPS 6 HDPE mainline.

20. The mainline will be installed within road allowances. The majority of this mainline will be installed using open trench construction methods. The mainline will be installed under most roads and major watercourses using horizontal directional drilling (HDD) methods where possible to avoid potential environmental impacts and to minimize the disruption to roads and highway operations.

21. Most of the smaller diameter distribution piping will be installed in already developed areas. Where possible the contractor will therefore use HDD installation techniques for the mains and services to minimize surface disturbances. Potential conflicts with other utilities will be daylighted during construction to avoid damage to these other utilities.

22. The entire distribution system will be designed and operated in accordance with the CSA Z662 code.

23. Union will provide gas service from its Owen Sound line in Dornoch as illustrated in Figure 7. Union has agreed to odourize the gas in a manner consistent with the odourization levels required by CSA Z662 code.

24. EPCOR will design and install SCADA systems to monitor and control the operations of the distribution system on an around the clock basis.

25. Further engineering specifications and details on the design of the pipe and pipeline system will be provided in the Leave to Construct (LTC) application. The pipeline and station facilities have been optimized to meet the forecast growth in the area.

26. Detailed maps of the proposed distribution system for each urban area are provided in Schedule B. EPCOR is aware that there are several planned new residential developments in Southern Bruce. EPCOR has included the capital cost to develop the distribution mains required to support an estimated 469 new homes during the first 10 years, however at this time the details of these development is not sufficient to illustrate the locations on the maps.

Environmental Considerations

27. The route of the proposed facilities was selected to optimize the economics of the Project and other socio-economic community benefits with a critical goal to abate environmental impacts.

28. There are a few of watercourse crossings associated on the routing proposed and the Design and Construction Plan will incorporate the environmental implications of these and various other environmental considerations by following the Board’s "Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in Ontario".

29. EPCOR retained the firm of Stantec Consulting from the outset (immediately after its selection as preferred franchisee by the communities in September 2015) to develop a preliminary preferred route for the proposed mainline and prepare the necessary ER including proposed mitigation measures for the project. Stantec is well underway to assess and complete an environmental screening for the proposed development plan for the distribution pipelines within the communities being served. Stantec will also work with the Ontario Pipeline Coordinating Committee (OPCC) to finalize the requirements to issue an ER for the project.

30. All construction activities will meet the requirements of the OEB's document "Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in Ontario".

31. The transmission line will be installed under most roads and major watercourses using horizontal directional drilling (HDD) methods where possible to avoid potential environmental impacts and to minimize the disruption to roads and highway operations. For the construction of the distribution systems, the contractor will use HDD installation techniques for the mains and services to minimize surface disturbances.

32. Stantec developed a study area for the mainline, identified alternative routes, conducted open houses along the route and obtained public input in order to identify a preliminary preferred route. Most of the environmental fieldwork has effectively been completed and will form part of EPCOR's Design and Construction Plan. Upon EPCOR being selected as the successful proponent from the CIP application, Stantec will conclude in short order the remaining limited fieldwork and conduct final public consultations to finalize the preferred route. Stantec will coordinate with the OPCC to complete the requirements to issue an ER for the project within 90 days of the OEB selecting EPCOR as the successful proponent. This ER will be submitted by EPCOR as part of the LTC application.

Material Specification

33. All the design specifications are in accordance with Ontario Regulation 210/01 under the Technical Standards and Safety Act, 2000, Oil and Gas Pipeline Systems.

34. The NPS 8 steel mainline from the Dornoch Interconnect with Union Gas to the Bruce Energy Centre will have a wall thickness of 4.8 mm, a yield strength of 290 MPa and will have Category I notch toughness properties. The NPS 6 steel mainline from the Bruce Energy Centre to Kincardine will have a wall thickness of 4.8 mm, a yield strength of 290 MPa and will have Category I notch toughness properties.

35. All measurement, valve site and pressure regulation facilities will be constructed with PN 50 rated materials.

36. The distribution systems will consist of piping ranging in size from NPS 6 to NPS 2. All distribution piping will be high density polyethylene (HDPE) as per the requirements of CSA Z662-15.

Construction Schedule

37. Schedule E provides the proposed construction schedule for the Project generally as agreed to under the common assumptions proposed as part of the Common Infrastructure Plan.

38. The following facilities are scheduled for construction in 2019:

- NPS 8 mainline from Dornoch to the Bruce Energy Centre
- NPS 6 steel pipeline from the Bruce Energy Centre to Kincardine
- The HDPE distribution system for Kincardine and Tiverton

39. The following facilities are scheduled for construction in 2020:

- NPS 6 HDPE pipeline to Lucknow
- NPS 4 HDPE pipeline to Point Clark
- NPS 4 HDPE pipeline to Ripley
- The HDPE distribution systems for Inverhuron, Paisley, Chesley, Point Clark, Lurgan Beach, Ripley and Lucknow.

40. Given that EPCOR had assumed that its Franchise approval by the OEB was a routine ratification, based on past practices, EPCOR has extended extensive effort on the Southern Bruce Project through its work on the ER and Design and Construction Plan in anticipation of submitting a Leave to Construct application shortly after the award of the original franchise application. EPCOR therefore believes that it can commence the construction in advance of the current proposed Board Staff schedule outlined in the OEB Staff Progress Update filed on July 20, 2017. This advanced schedule option has been further detailed under Section 5: Other Value-Added Factors.

Community Consultation

41. In September 2015, EPCOR was announced as the successful proponent by the municipalities of Kincardine, Arran-Elderslie and the township of Huron-Kinloss in their municipal-led competition to supply natural gas to the region. Since then, EPCOR has worked in partnership with the municipalities to understand the requirements of residential, commercial, industrial, farm/agribusiness and institutional customers. This includes sponsoring a series of community open houses in partnership with the municipalities: Thursday, October 15, 2015 at the Chesley Community Centre, Friday, October 16, 2015 at the Ripley-Huron Community Centre and Saturday, October 17, 2015 at the Kincardine Municipal Administration Building. Over the last two years EPCOR has also directly engaged with large customers and agricultural customers in the project area to understand their demand and economics required to convert to natural gas.

42. In 2017, EPCOR opened a customer care centre in Kincardine to talk directly with customers on the economics of converting to natural gas. To date many residents, business owners and farmers have visited the customer care centre and the information collected from these potential customers is consistent with the telephone survey results. EPCOR has also worked with the municipalities to take this customer care centre on the road to local events.

43. EPCOR has plans to use this Queen Street Kincardine location of its customer centre to conduct customer conversion clinics on weekends, post LTC approval to help meet its conversion targets. To-date EPCOR's acceptance in the communities has been welcoming and tremendously positive.

44. EPCOR has utilized two surveys to inform the customer and demand profiles for this project.

    i. Border Ladner Gervais LLP (BLG) - Business Case for Expansion of Natural Gas Distribution in Southern Bruce County. Surveys were conducted by telephone among residents and small-medium sized business establishments most likely to be in the service area, as identified by 6-digit postal code. This survey was conducted from July 31, 2014 to August 6, 2014. The survey included 753 respondents. These results are considered accurate to within ±3.6%, 19 times out of 20.

    ii. EPCOR Survey. Surveys were conducted by telephone among residents in the service area, as identified by the proposed pipeline alignment. Sampling was conducted with a stratified sample of permanent residents and non-permanent residents with properties in the service area from each municipality. The main sample was listed landlines in the service area. Additional sample of non-permanent residents were identified based on households who use a mailing address outside of the sample region to receive their property tax bills. The strata of permanent residents were weighted by municipality and household size according to Statistics Canada data. The residential survey was conducted by telephone among 554 randomly-selected households within the sample area, between July 6, 2017 and July 17, 2017 and the results were weighted to 500. The overall results are considered accurate to within ±4.4%,19 times out of 20.

45. In October 2015, EPCOR contacted the following First Nations and Metis Communities, delivering to them a Letter of Commencement for the project, notification of open houses and an invitation to either attend the open house or request a community meeting if it better suited their needs.

    - Saugeen First Nation
    - Chippewas of Nawash Unceded First Nation
    - Metis Nation of Ontario Great Lakes Metis Council
    - Historic Saugeen Metis
    - Beausoleil First Nation
    - Chippewas of Kettle and Stony Point First Nation

46. In November and December of 2015, the Saugeen First Nation and Chippewas of Nawash Unceded First Nation (acting together as the Saugeen Ojibway Nation) and the Historic Saugeen Metis both requested and EPCOR had face-to-face meetings with them to learn about the project. The Metis Nation of Ontario contacted EPCOR by telephone around the same time and asked questions about the project but did not request to meet at that time. However, in May 2017 they requested a face-to-face meeting to learn more about the project. Once EPCOR has been chosen as the successful proponent, EPCOR will work closely with these First Nations and Metis Communities on involvement in the successful outcome of this project.

Operational Costs and Allocations

47. For OM&A costs, EPCOR has fully allocated costs to this expansion project.

48. With over 125 years as a utility provider, EPCOR has the experience and knowledge to adequately forecast fully allocated OM&A costs for new operations. EPCOR's OM&A cost estimate has been developed to ensure a safe, reliable, cost-efficient, and environmentally responsible operation of the distribution system to be located in Southern Bruce. The OM&A cost estimate has been determined on a "bottom-up" approach. Leveraging the knowledge of internal subject matter experts and external consultants, the OM&A budget assesses the needs of the distribution system, considering length of pipe, customer connections, and emergency response requirements, and seeks to maximize the operational life of the system assets, ensuring a safe, and cost-efficient distribution system for ratepayers.

49. In all of EPCOR's existing utility operations, EPCOR incorporates a fully allocated cost of service model for its operational estimates. By working with regulators such as the AUC, EPCOR follows internationally recognized standards; the costs allocated within utilities should, as much as possible, reflect the services provided to ratepayers. Cross-subsidization is prevented via: proper cost of service allocation within the utility, and proper Corporate Shared Services cost allocations (e.g. overheads), as discussed below.

Cost of Service Allocation:

50. This portion of fully allocated costs ensures that rates borne by specific customer classes are fair and equitable. A full cost allocation study will be included in its submission of a rate application to the OEB, at which point EPCOR will incorporate the fundamental importance of ensuring customer classes are treated fairly. The Cost Allocation Study will include step-by-step schedules depicting the approach used in rate design, and the resulting revenue-to-cost ratios. EPCOR will implement prudent and fair rate design as is done with its current utility customers, and will be adhered to in its Ontario natural gas operations. The rate design will identify costs that are rate class specific (e.g. Industrial) and allocate such accordingly. Below are rate design principles set out by the AUC that are fundamental to EPCOR's operations:

   - Allocation should reflect cost causation
   - Allocation should be reasonable (fairly attributed) and supportable
   - Allocation should be cost effective
   - Allocation should be stable over time
   - Allocation should be transparent
   - Allocation should cause 'no harm' to customers

Corporate Shared Service Costs:

51. EPCOR allocates Corporate Shared Service costs justly amongst its operations. Regulated by the AUC, EPCOR's Distribution and Transmission group (EPCOR Distribution and Transmission Inc.) has been prescribed to ensure proper separation of corporate costs to guarantee ratepayers are only responsible for costs that can be fairly allocated to the service they receive. EPCOR's Edmonton water operations (EPCOR Water Services Inc.) are regulated by the City of Edmonton; In these utilities, EPCOR still applies, where determined to be prudent, the more stringent regulations set out by the AUC. EPCOR has extensive experience

in properly allocating corporate costs to a specific utility, ensuring no cross-subsidization takes place, and is confident it can adhere to the robust and industry leading standards set by the OEB.

52. EPCOR Southern Bruce Gas Inc. would obtain corporate services from its parent corporation, EUI. Corporate services are comprised of activities that are centrally managed within the EPCOR group due to their nature and/or for the purpose of realizing economies of scale and greater effectiveness. Over 50 departments and functions are considered to be providing corporate shared services; corporate finance, treasury, human resources, public and government affairs, legal services, and health, safety and environment are a few examples of the support provided by EUI. The amounts paid by the Southern Bruce utility in respect of these services form corporate shared service costs. The corporate shared service costs are determined on a cost recovery basis in accordance with EPCOR's Inter-Affiliate Code of Conduct and are reflected in a Service Agreement between the parties. EUI allocates corporate shared services costs to the EPCOR business units using the following five step process:

- Categorize corporate shared services costs as directly assignable or allocable
- Assign directly assignable costs to the appropriate business unit
- Review/develop/modify allocation method for allocable costs
- Apply allocation method to allocable costs
- Conduct a final review for reasonableness

53. EPCOR's cost allocation process is designed to ensure that the allocation of corporate shared service costs among business units is appropriate, fair and reasonable, cost-effective, predictable, and reflects the benefit received by function or cost causation. The costs associated with a corporate services department are allocated on one of two bases: (i) using a "functional cost causation allocator"; or (ii) using a "composite cost allocator".

54. 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 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 EPCOR's group revenues, assets, and headcount.

55. This analysis has been conducted for EPCOR Southern Bruce Gas Inc., and the OM&A estimates fairly reflect the costs associated with corporate services received from EUI.

Royalty Payments

56. EPCOR has agreed to provide its partner municipalities (Arran-Elderslie, Huron-Kinloss, and Kincardine) a royalty payment amounting to 1% of anticipated revenues. However, in the letter of support attached in Schedule A, the municipalities have foregone this royalty for the first 10 years, as a result, this value has been excluded in the OM&A estimates and the resulting Revenue Requirement provided in this CIP submission.

Operational Cost Exclusions

57. EPCOR is required to obtain upstream natural gas transportation service to Dornoch from Union. Union has refused to make available to EPCOR its existing Board approved services that are available to other embedded utilities such as NRG. Instead, Union proposes a new service, that is yet unapproved by the Board, that will require EPCOR to actively manage its supply and transportation through daily nominations and supply acquisition. Union's existing M9 service to embedded distributors does not have this daily workload burden. Union has advised that it will seek approval of this new rate subsequent to the Boards' decision on the CIP. EPCOR is not in agreement with Union limiting EPCOR's access to Union's proposed new service.

58. As a result, and, consistent with the Board's direction in the Decision on page 7 of the Preliminary Issues and Procedural Order No. 8, dated April 22, 2017 on upstream reinforcement, the OM&A costs associated with managing Union's proposed service and the resulting task of daily supply and transportation management have been excluded from this submission.

59. Additionally, the OM&A estimate excludes all costs agreed to by EPCOR and Union to be excluded from submission. A list of these items is located in Tab 4, "Common Exclusions Agreed by the Parties".

Capital and Operational Cost Certainty

60. The Board indicated in its Decision on Preliminary Issues and Procedural Order No. 8 Dated August 22, 2017:

> *"As determined in the Generic Proceeding, the OEB finds that any capital cost overruns incurred during the first 10 years above the forecasted costs reflected in the proposals will not be permitted into the successful proponent's rate base for year 11 and beyond (following the rate stability period). The treatment will be symmetrical: cost underruns will accrue to the utility's benefit.".*

61. EPCOR accepts this arrangement regarding cost overruns and underruns and has prepared its Revenue Requirement on this basis. Both the capital costs, as well as operational costs have been designed to meet the parameters of a 10 year rate stabilization period.

EPCOR Revenue Requirement

Overall Revenue Requirement

62. EPCOR has done a comprehensive analysis of the Southern Bruce distribution system and has at all times considered safety of the surrounding community, cost-efficiency for ratepayers and meeting the Board's SQRs. The Revenue Requirement has been determined on the Utility Basis Approach seen below in Figure 8:

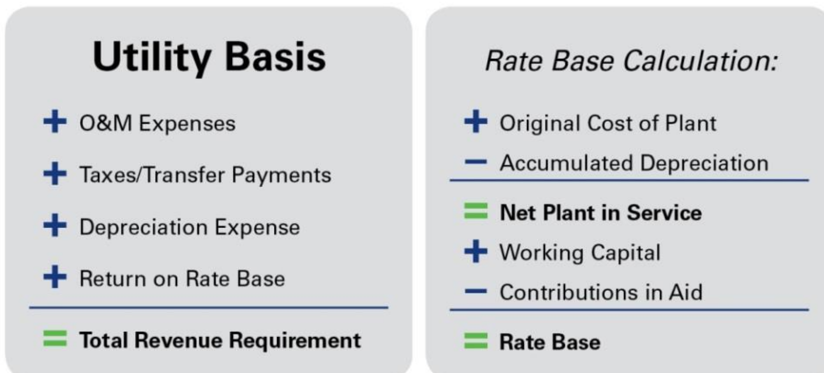


Figure 8: Utility Basis Approach

63. Full cost allocation in the form of assigning all Southern Bruce utility costs fully to the project and ensuring no cross-subsidization when creating the Revenue Requirement has been considered. The Revenue Requirement includes full design, build, operating, financing and maintenance costs associated with the Southern Bruce natural gas system. The depreciation expense considers each asset class to be depreciated on a straight-line basis accounting for the assets' respective life. These depreciation estimates are in line with the common assumptions used for this CIP submission.

Annual Revenue Requirement

Table 5: Annual Revenue Requirement (2019 – 2028)

Year ($)									
2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1,332,492	4,388,984	6,155,922	7,534,172	8,488,867	9,122,050	9,406,087	9,567,338	9,722,807	9,864,542

Net Present Value of Revenue Requirement

At a 4% discount rate, the NPV of the Revenue Requirement for the 10 year 2019-2028 period, calculating the annual values as end of period, and as of ***December 31, 2018*** amounts to $59,072,317.

Cumulative Revenue Requirement

64. The Cumulative Revenue Requirement for the 10 year 2019-2028 period amounts to $75,583,261.

Key Assumptions / Exclusions

65. As noted in Tab 5, “Operational Cost Exclusions”, transportation costs from Dornoch, associated reinforcements and potential OM&A costs have been excluded from this CIP submission.

66. Additionally, the OM&A estimate excludes all costs agreed to by EPCOR and Union to be excluded from submission. A list of these items is located in Tab 4, “Common Exclusions Agreed by the Parties”.

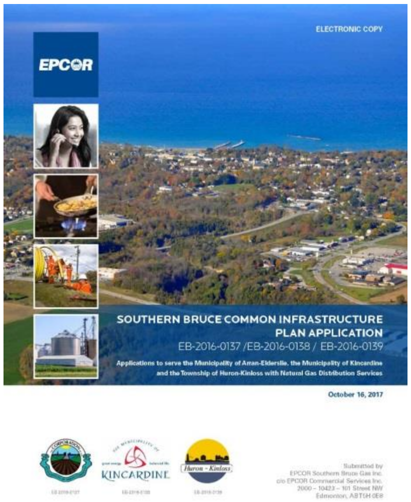
Annual Costs and NPV Requirements

67. The Board indicated in its Decision on Preliminary Issues and Procedural Order No. 8 Dated August 22, 2017 determined that:

> *“For the purpose of structuring a common platform for selection purposes, the OEB finds that proponents should price their revenue requirement proposals based on the assumption that there will be no rate adjustments during the 10-year rate stability period, other than the availability of Z-factor relief for certain events that fall within the OEB’s policy”.*

68. EPCOR accepts this 10-year rate stability period for the delivery rates. The revenue requirement has been prepared on this basis. EPCOR has incorporated the annual inflation adjustment of 1.27% as referenced in Schedule C in calculating its Revenue Requirement.

69. The NPV calculation has used inflated values, a 4% discount rate, and end of year discounting as agreed to by EPCOR and Union for this CIP submission.



TAB 6

CIP Rate Making Comparison Criteria

4.CIP Rate Making Comparison Criteria

EPCOR Planned Cost per m^3

1. Including all inflationary adjustments, the cost per m^3 for the 10 year 2019-2028 period is as follows:

Table 6: Cost per m^3 for Period 2019 - 2028

Item	Value
Cumulative Revenue Requirement ($):	$75,586,261
Total Volumes (m^3):	428,035,564
Cost per m^3	0.1766 $/ m^3

EPCOR Planned Number of Customer Years

2. The Number of Customer Years over the 10 year 2019-2028 period for each customer class is as follows:

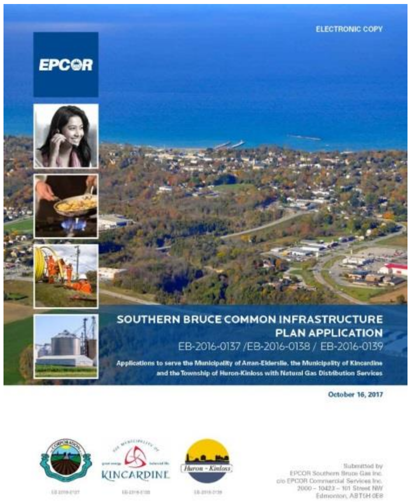
- Residential: 38,919
- Commercial: 3,542
- Industrial and Agricultural: 108
- Total: 42,569

EPCOR Planned Cumulative Volume

3. The cumulative volume over the 10 year 2019-2028 period is: 428,035,564 m^3. This value considers volumes dependent on the type of customer. Therefore, volumetric customers include forecasted natural gas annual usage, whereas capacity contracts would use the full annual capacity. Tabs 4, “Customer Consumption Levels” and 5, “CIP EPCOR Proposed Parameters” detail the assumptions regarding volume further.

EPCOR Commitment to Planned Rate Making Outcomes

4. When allocating costs to ratepayers of a utility, it is EPCOR’s intent to ensure ratepayers are paying a fair and stable rate for the services received. Each customer class should bear their fair share of costs – EPCOR has considered this from the inception of the work done for this submission. While a detailed rate study is not required at this phase, there is value in considering these factors early on, influencing design, and resulting costs. In accordance with the OEB’s decisions noted previously in this CIP Submission, EPCOR is committed to a 10 year rate stabilization period and the resulting responsibility for cost fluctuations. EPCOR is confident its submission provides a fair, stable, cost-efficient, and equitable Revenue Requirement to be borne by ratepayers.



TAB 7

Other Value-Added Factors

5. Other Value-Added Factors

The OEB's Rate Making Principles and Expectations

1. OEB's Renewed Regulatory Framework for Electricity Distributors and its Handbook for Utility Rate Applications, proposes increased customer focus and a shift from cost recovery to long term value for money. EPCOR through this submission proposes such an approach to extend to gas distribution in Ontario.

2. Under the Renewed Regulatory Framework for Electricity (RRFE), the OEB outlines four specific categories of outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. Under the customer focus outcomes it states:

   "Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences. [Emphasis added]"

3. In the Southern Bruce franchise area, EPCOR is directly aligned with the Board's goals to deliver value for money through its life cycle cost principles and ensuring pro-active control of costs and risks. From the onset, EPCOR has been diligent in seeking out other value-added opportunities to reduce costs for its customers by working with its municipal partners and agro-businesses. This section outlines those opportunities that have already been identified with some incorporated into its business plan for Southern Bruce. Furthermore, given the strong relationship that EPCOR has already developed with its municipal partners, EPCOR anticipates being able to continuously seek out additional synergies to reduce costs for both its customers and taxpayers.

4. EPCOR is also committed to managing risks and under the Executive Summary section notes its willingness to take on risks that utilities have traditionally asked customers to bear. This approach incents EPCOR to effectively better manage these risks.

EPCOR is the Preferred Partner for the Communities

Municipal Franchise Selection Process Carefully Selected EPCOR

5. The OEB franchise selection process in 2015 required the municipality, and the gas distributor to come to an arrangement and propose a Franchise Agreement to the OEB for approval. In spring 2015, a franchise selection process was undertaken by the three southern Bruce County municipalities, motivated in part, by the anticipated Government sponsored natural gas grant and loan program. A carefully executed competitive Request for Proposals process, open to potential natural gas providers in Canada and the United States, resulted in the selection of EPCOR as the successful proponent among several applicants, including Union Gas. EPCOR was selected as the community's franchise partner of choice, and subsequently entered into

franchise agreements with the municipalities. These franchise agreements were submitted to the Board for approval.

6. A Generic Hearing was initiated by the OEB and as a result the franchise agreements between the Southern Bruce communities and EPCOR were put in abeyance. Since then the communities and EPCOR have continued to work together to refine the Project. EPCOR and Southern Bruce communities have undertaken many initiatives to help improve the Project economics and ensure the Project focuses on economic development initiatives within the agriculture and industrial sectors of the communities, and to make the Project ready for rapid implementation post-franchise and grant approval.

Confirmation of Support & Ongoing Community Confidence

7. Today, almost two years after EPCOR's selection as the preferred franchisee the community leadership have not wavered from their support of EPCOR as their preferred choice. The communities even as this Project witnesses yet another round of selection, feel a greater level of confidence in their selection of EPCOR as their designated franchise partner and see joint opportunities in developing a successful natural gas utility with a compatible utility partner with whom they can explore a mutually beneficial and long-term infrastructure and economic development alliance. A letter of support Schedule A from the three municipalities confirms this optimism and reiterates its endorsement of EPCOR.

8. EPCOR and the communities while collaborating in developing the natural gas Project, have also landed on some significant other value-added initiatives that will directly benefit the Project as well as tax payers in the communities. These other value-added initiatives are more fully described below:

Towards a Multi Utility Partnership

9. Municipalities and utilities today are facing observable trends and challenges that are requiring a re-examination of the traditional utilities model. These trends include:

   - Changes in customer expectations and behavior due to evolving demographics, advancement in technology, and demand for a greener solution;
   - New forms of competition that are eroding some of the natural monopoly aspects of traditional public utilities;
   - Economic implications of climate change;
   - Fiscal, environmental and other pressures from policy makers, regulators and stakeholders; and
   - Infrastructure renewal imperatives.

10. In the communities of Southern Bruce, the provision for a natural gas service has been a decade's long goal and the communities saw the need for non-traditional approaches to find a way to obtain access to this service, the lack of which has disadvantaged economic development, residential growth, and affordability perspective for years. In EPCOR, they saw a like-minded partner operating as an integrated utility company providing electricity distribution, transmission, water, and wastewater services, fibre networks and saw natural gas as a natural opportunity to explore the synergies of the various utility services as a potential for improved

service provision. The City of Kingston and City of Kitchener, all demonstrating such value, were a good benchmark to have provided the communities the appreciation of the possibilities.

11. The parties therefore saw the long-term prospect of further enhancing their ability to grow, provide cost effective services, and finding ways to align the various services with a view to achieving synergies from multiple utility services such as electricity distribution and affiliate opportunities, natural gas, and water & wastewater under either a common platform or inter-company service level agreements to realize such synergies and reduce costs to the ultimate ratepayer and/or taxpayer. Figure 9 depicts an approach to multi utility based synergies that were considered.

Figure 9: Multi Utility Partnership Opportunities Explored

12. Over the last two years in EPCOR's dealings with the Southern Bruce communities, various other synergistic initiatives have continued to be explored. As the Project moves toward final approval, the communities see joint opportunities to developing a successful natural gas utility.

Planned Synergies on Fibre and Water Partnerships

13. Two synergistic initiatives that the partnership between the communities and EPCOR has yielded, relate to the potential for co-construction of utilities including joint construction of a water pipeline and fibre optics network during the construction of the natural gas lines in the communities. Both opportunities are expected to reduce the overall Project construction costs and in the process, increase gas pipeline safety and reliability, creating an economic development boost for the community, offer ratepayers potential for additional services, and providing lower than planned natural gas rates for end users. The proposed two initiatives that were explored in detail are as follows:

    i. EPCOR and Bruce Telecom, the Municipality of Kincardine owned telecommunications company, have investigated the opportunity to co-construct a new fibre optic cable network while constructing the natural gas pipelines. This approach is expected to enable each household to have access to high speed internet and would provide the gas pipeline system the ability to to be monitored for safety through optically based sensing for potential failure and disturbances leading to leaks. The proposed construction configuration now adopted by the industry is provided in Figure 10. The Southern Bruce communities, given this green field construction opportunity, can benefit from this new technological innovation by offering households a cost-effective manner to receive two additional utility services – natural gas and high-speed internet simultaneously. EPCOR has worked closely with the contractor and TSSA to determine the cost savings of such concept and doing so in a way that is consistent with all natural gas pipeline codes.

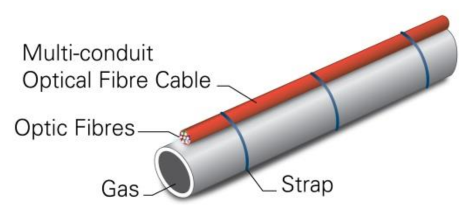


Figure 10: Gas Line with Optical Fibre

    ii. The Municipality of Kincardine is currently planning water and wastewater pipeline extensions to various new developments and industrial parks within its municipalities. One such Project is expected to follow the same routing as the proposed natural gas lines and the synergy of co-construction is being planned as part of this Project. Co-construction of the natural gas line to coincide with the installation of the water pipeline will allow for obvious synergies between the Projects to the cost benefit of both utilities. The water service is expected to enable the community to provide safe drinking water to residents/businesses that are currently either not serviced or receiving poor quality water with health risks. The natural gas ratepayers will benefit from the

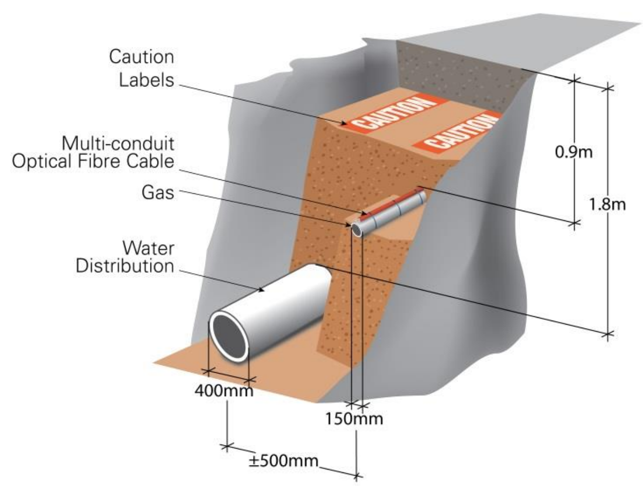


Figure 11: Multi-Utility Co-construction

synergies through reduction of construction costs of the natural gas pipeline as an outcome of the construction synergy. Finally, the Municipality of Kincardine will be able to service the industrial park with water and wastewater services to allow the park to attract further economic development for the community with creation of new employment and additional property tax and utility rate revenues.

14. In total, the above initiatives are expected to yield a direct capital cost savings for the natural gas Project of about 3-5% that has been included in lowering the Revenue Requirement being proposed.

15. The work that the municipalities and EPCOR have put in the last 24 months are centered around two core concepts, minimizing costs for ratepayers, and providing economic value to the communities. This integrated utility approach will not only drive the success of delivering natural gas to Southern Bruce, but also drive economic growth, and enhance the wellbeing of the residents through innovative safety measures, and cost-effective delivery of industry leading technologies.

An Early Project Commencement Schedule

16. One other factor of significance that EPCOR and the communities believe is an advantage for EPCOR is having the ER for the Project close to completion. After the communities concluded its competitive RFP solicitation process and selected EPCOR as the Franchisee for the distribution of natural gas, EPCOR and the municipalities anticipated a straight forward process for approval from the OEB. To that end, and based on the strict timelines set by the communities to have natural gas in place by 2018, EPCOR commenced the ER process to expedite the Project's implementation and public engagement process. In the meantime, EPCOR and the communities have nevertheless made considerable progress in concluding the majority of the ER work on the EPCOR portion of the pipeline and expect the ER process to be completed within 6 to 10 weeks of the franchise award by undertaking final community public open houses and receive feedback from all stakeholders to inform the routing finalization.

17. EPCOR believes that this advantage provides the following benefit to the Project:
    i. A one winter advancement of the Project's implementation provides improved viability on the Project economics;
    ii. Mitigate the loss of further co-construction synergies and enhancing the current synergies if approvals happen in a timely manner; and
    iii. A partial ground breaking for the Project in 2018 would allow EPCOR to take a step toward meeting the commitments it made to the municipalities when first selected as their preferred franchisee.

18. To provide a better understanding of the proposed EPCOR Schedule advantage, Figure 12 below summarizes the proposed differences in the implementation plans that can transpire if timely decision can be attained.

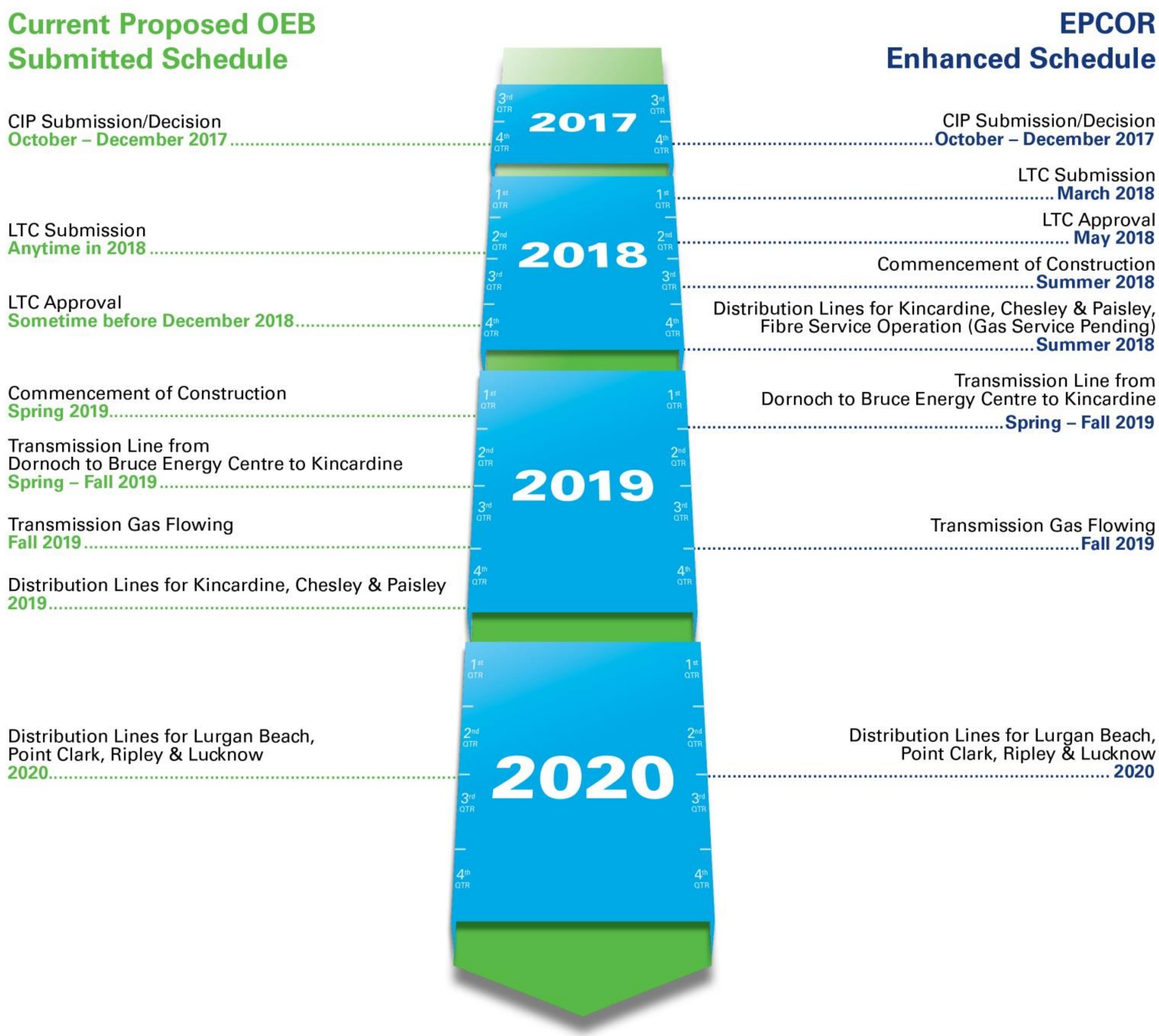


Figure 12: Comparing Current Proposed Schedule with the EPCOR Enhanced Schedule

Expansion of the Greenhouse Business in the Community

19. In 2016, a greenhouse agro-business reestablished itself under a new ownership with plans to expand. Unfortunately, this business needs to expand but faces a challenge with the supply and cost of its electricity, as well as land requirements for its expansion needs. If energy cost barrier to expansion is not overcome, the business will need to locate its expansion to another site outside of the proposed franchise community. The business currently also inefficiently meets its substantial cooling and heating needs. As part of this natural gas initiative, EPCOR brought its extensive multi-utility expertise and existing municipal partnership to bear by facilitating the introduction of a CHP based co-generation facility to meet the enterprise's heating and cooling

needs and in the process enabling the generation of electricity on a leased municipal site to improve the current economics of the greenhouse business with a view to expand the co-gen site to augment the expansion electricity requirements. If the expansion initiatives were to be successfully serviced with additional co-generation opportunities that the parties, including the Municipality of Kincardine, are jointly investigating, besides the prospect of the enterprise expanding at its current location, the gas utility stands to realize significant increase in the natural gas demand of the expanded facility and bring economies of scale benefits to the ratepayers of the Natural Gas Project. It is EPCOR's intention to pass on this volumetric gain to the project through lower rates for ratepayers.

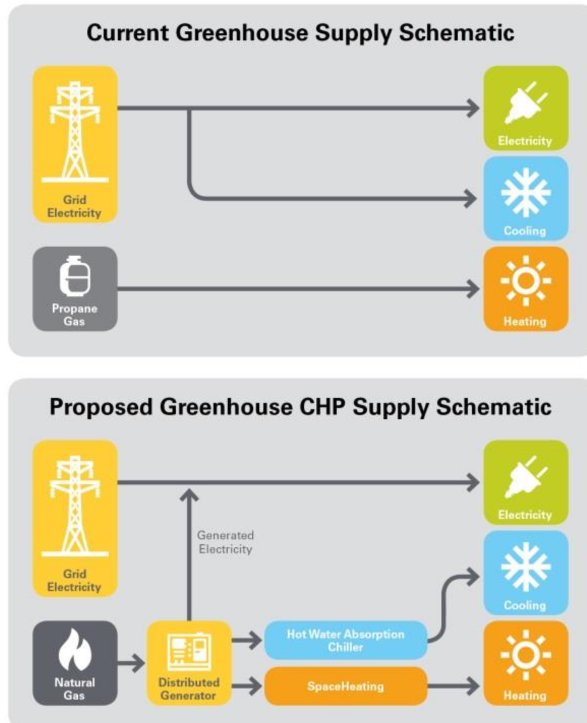


Figure 13: Co-Generation Facility for Greenhouse

20. Table 7 below compares the existing boiler based heating and cooling natural gas volumes proposed under this CIP application to the OEB with additional demand volumes under an expanded co-generation scenario to meet the heating, cooling and electricity needs of this facility:

Table 7: Proposed Annual Natural Gas Demand Volumes for the Greenhouse Operations

Description	Under Existing CIP Application with Boiler based HVAC	Based on Co-Gen HVAC with Electricity Generation at existing Facility	Based on Expanded Facility with Co-Gen
Volumes of Natural Gas Consumed m^3/year	2,000,000	8,250,000	12,500,000
Impact to $/m^3$ on this CIP Application	0%	-3%	-8%
Resulting $/m^3$ on this CIP Application	0.1766	0.1710	0.1623
MW of Electricity Produced	0.0 MWe	3.3 MWe	5.0 MWe
MW of Thermal Energy Produced	2.5 MWth	5.0 MWth	7.5 MWth

Other Proposed Future EPCOR-Municipal Partnerships

21. As noted previously, EPCOR's strong relationship with the communities and its leadership has been ongoing and strengthened over the last 24 to 30 months. During this time, the parties have worked as partners not only to develop new and creative ways to enhance this Project but also to explore how EPCOR, with its broad integrated utilities background and financial wherewithal, can bring about other economic development initiatives to help the municipalities and in the process, improve the natural gas project benefits to the ratepayers. The municipalities and EPCOR believe that in the long term, Project success will largely depend on finding creative synergies by way of the economies of scale, such as through a collaborative utility platform. This collaboration and resulting benefits have already been identified in the past 24 months through construction synergies and other value-added benefits that now remain to be realized. Below are some concepts and ideas that are being further explored with a view to develop and implement them where prudent and receives stakeholder support.

Further Operational and Organizational Alliances Going Forward

22. Since the selection of EPCOR as the municipalities' preferred utility franchisee, discussion surrounding alliances to benefit the communities and their respective rate and taxpayers has been ongoing. The municipalities have always recognized that EPCOR, with its multi utility background can provide a strategic fit and the parties could form a mutually beneficial alliance.

23. One key area of alliance that is envisaged and on confirmation of the EPCOR franchise award is to explore further gas utility level operational efficiencies through either service level agreements ("SLA") or formal alliance agreements to find additional synergies of mutual benefit.

24. In Figure 14 a multi-utility collaboration has been summarized. Prior to the Leave to Construct (LTC) application, EPCOR anticipates that some of these collaboration opportunities, if firmed up and operational efficiencies are realized, will form part of the LTC. Note that none of these efficiencies have been incorporated into this submitted CIP submission.

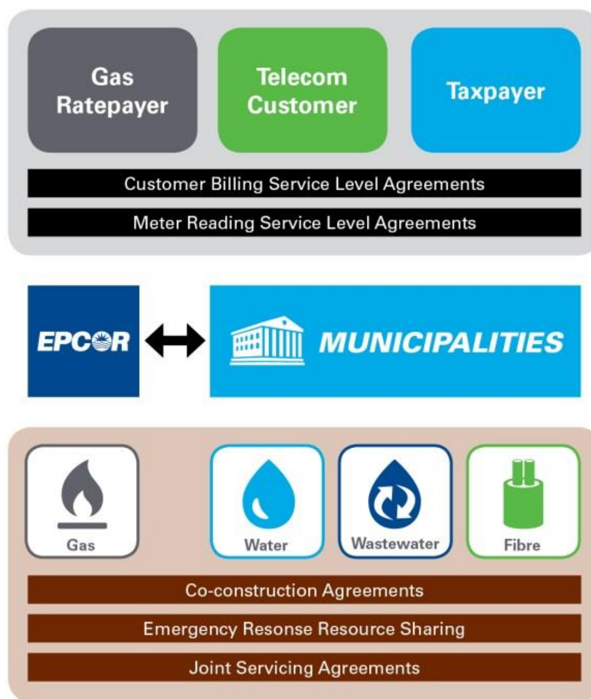


Figure 14: Multi-Utility Collaboration for Service Efficiencies

Additional Multi-Utility Servicing of Employment Lands in the Community

25. In anticipation of the Bruce Power's Major Component Replacement (MCR) project which entails the life extension of six Bruce Power units over a decade with an estimated expenditure of $13 billion, the Municipality of Kincardine plans to position itself for the resultant growth that

will come about. The community leaders understand the lack of natural gas service in the community during the last economic boom resulted in significant economic development opportunities being lost to adjoining communities.

26. Since EPCOR's selection as the preferred franchisee in 2015, discussions have been ongoing to work jointly to service new business parks within the municipalities so major contractor and supporting businesses may locate in the municipality to provide the necessary support to the ongoing refurbishment of the Bruce Nuclear Power Plant. While there is ample raw land available in the area, there is a lack of ready utility serviced business parks and employment based commercial and industrial land available. EPCOR has been in discussions to explore the multi-utility servicing of these lands on a fast track basis under a potential alliance arrangement to enable businesses to locate in the municipality to the benefit of both the gas utility and the municipality.

Figure 15: Multi-Utility Servicing of Proposed Lands in Kincardine

27. The above effort is in keeping with the spirit of what the municipality and EPCOR saw from the outset as a value not only to the Project, but EPCOR's value as a strategic partner with a multi-utility dimension to help grow the community. It is the intent of EPCOR and the municipalities if EPCOR is selected as the Franchisee by the OEB, to determine if this servicing of the business parks can be undertaken in a timely manner before the economic wave of new businesses is once again lost to the neighboring communities as was the case in the past.

Financing and Expansion of the Fibre Optics Services

28. As previously noted, the municipally owned telecommunications company has jointly explored with EPCOR, to determine whether additional benefits to the Project, and subsequently, ratepayers can be achieved through a cooperative planning and implementation strategy related to the expansion of a fibre network. Under this alliance, the telecommunications company has expressed a desire to work with EPCOR to co-construct part of its fibre optic network with a view that synergies may be shared between the two initiatives.

29. As part of the fibre optic network co-construction initiative, the parties are exploring the possibility of EPCOR extending financing to the fibre optics network project co-construction through a Public Private Partnership of a Design-Build-Operate and Finance delivery of the Project that the municipality finds of significant value.

30. This financing opportunity will be undertaken independent to the natural gas servicing Project, but the coincidence of the Projects aligning provides an important synergy value typically not available on such a Project.

31. These initiatives will not in any way alter the independent and standalone principles of the proposed regulated gas utility and nor will any risks related to co-construction or financing or development will be borne by the utility or its ratepayer. However, the value of the deep relationship the parties would like to engage in are evident and in keeping with the broader benefits that will accrue to both parties and the respective infrastructure developments.

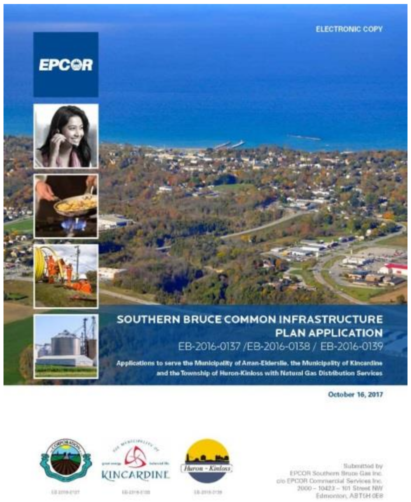
Park Trail Co-Construction Initiative

32. The Municipality of Kincardine and the County of Bruce in conjunction with Kincardine Trails Association are currently developing a 12 km Kincardine to Inverhuron Provincial Park Trail (“KIPP” Trail). The Trail is being funded by local community businesses and individual support and government grant programs. Off the 12-km trail run, a 5 km stretch (Phase 2A) coincides with the current natural gas pipeline construction project that routes through Bruce Road 23 (B-Line) between Kinhuron and Westridge development as shown in Figure 16.

33. EPCOR has extended to the community an offer as part of its Project development plan to construct this trail under a co-construction initiative while installing the pipeline, and help pave this stretch for recreational use without any direct subsidy from the natural gas project. The proposal lowers the KIPP development costs to the community trail users without any negative impact to the otherwise capex implications of the natural gas Project. It is estimated that such an initiative would provide a synergy savings of $300,000 towards the community to lower their budget by 30%.

Figure 16: Kincardine to Inverhuron Provincial Bike Trail

34. This initiative once again shows the value of the partnership relationship that has developed between the municipalities and EPCOR over the period since its selection as the preferred Franchisee for the Project.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EPCOR

SOUTHERN BRUCE COMMON INFRASTRUCTURE PLAN APPLICATION

EB-2016-0137 /EB-2016-0138 / EB-2016-0139

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with Natural Gas Distribution Services

October 16, 2017

Submitted by
EPCOR Southern Bruce Gas Inc.
c/o EPCOR Commercial Services Inc.
2000 – 10423 – 101 Street NW
Edmonton, AB T5H 0E8

Schedule A
Municipalities Letter of Support

Municipality of Kincardine
1475, Con. 5, RR #5
Kincardine, ON, N2Z 2X6
519.396.3018

Township of Huron-Kinloss
21 Queen Street, P.O. Box 130
Ripley, ON, NOG 2RO
519.395.3735

Municipality of Arran-Elderslie
Bruce Road #10
Chesley, ON, NOG 1LO
519.363.3039

October 13, 2017

Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: EPCOR's Common Infrastructure Plan (CIP)

EB-2016-0137, EB-2016-0138, EB-2016-0139

Dear Board Panel Members:

The Municipality of Arran-Elderslie, the Municipality of Kincardine, and the Township of Huron-Kinloss (collectively, "Southern Bruce") is pleased to submit this letter in support of EPCOR's Common Infrastructure Plan ("CIP") to serve our respective communities with natural gas services.

The three municipal governments that comprise the Southern Bruce group have devoted the past 6 years to achieve access to natural gas for our residents, businesses and farms. This time consuming and resource intensive initiative continues to be critically important to the future well-being and prosperity within our region. This collective work also represents a powerful example of how small municipalities can effectively and cooperatively work together to achieve creative solutions to benefit their communities through providing access to lower cost energy alternatives.

If Southern Bruce had not developed a comprehensive business case and thereafter pursued our international, competitive solicitation process to obtain proposals from potential Canadian and American natural gas providers, Ontario would not have the opportunity to now welcome EPCOR, a multi-billion dollar 100% municipally-owned Canadian company and new entrant, into Ontario's natural gas sector.

Southern Bruce's continued support for EPCOR and the CIP Application which EPCOR will file with the OEB on Monday October 16, 2017 is based on the following key factors and considerations:

1. Our municipalities, in particular Arran-Elderslie and Huron-Kinloss, have a significant proportion of rural and agricultural consumers. A critical distinguishing feature of EPCOR's proposal from the very beginning was the commitment to serve all Southern Bruce communities. As a collection of small rural communities, our residents, businesses and farmers desperately require access to lower cost energy alternatives. However, those of us who live in rural Ontario often find ourselves being "left behind" with respect to energy choices and alternatives that other parts of Ontario take for granted. EPCOR has been stalwart in its firm commitment to provide natural gas service to all of our communities. We believe the OEB should consider this important obligation in its evaluation of EPCOR's CIP.

2. Like most Ontario municipalities, Southern Bruce continues to face serious and acute challenges with respect to infrastructure renewal. Roads, bridges, hospitals, schools, water, waste water systems, telecommunications networks and community centres all need to be upgraded, expanded or replaced. In many cases infrastructure renewal has become the central challenge for Ontario's municipal sector and this essential work will continue for many decades to come. In working with EPCOR Southern Bruce hopes to transform this daunting challenge into an opportunity. Only EPCOR has come forward with the interest, experience, creativity and financial capacity to present an interesting and compelling vision to explore synergy savings in areas such as telecommunication network expansion and water/waste water renewal and expansion with a view to reducing costs as part of its construction of the new natural gas distribution system. Synergy savings may span a wide range of activities from service level agreements to potential co-construction projects. A more detailed description of these matters can be found in the Value Added section of EPCOR's CIP. Accordingly, we ask the Board to consider this larger opportunity which EPCOR represents to all of our communities.

3. The Southern Bruce municipal Councils have already all approved making a direct financial contribution towards the proposed natural gas access project in an amount equivalent to the municipal property tax that would be recovered on the new natural gas infrastructure for a minimum period of 10 years. We estimate that this municipal financial contribution has a net present value of between $3M to $5M which is a significant amount for small communities. Southern Bruce has also agreed to work with EPCOR in seeking tax exemptions from other levels of government such as neighbouring municipalities and at the county level.

4. The Board will also note that in its CIP EPCOR has agreed to provide the Southern Bruce municipalities with a royalty payment amounting to 1% of anticipated net revenues. We

estimate that the net present value of these payments to be approximately $500,000 in total over 10 years. Southern Bruce is pleased to advise the Board that it will forgo collection of this royalty fee for the first 10 years to further assist the overall economics of the project.

In summary, Southern Bruce supports EPCOR as its preferred provider of natural gas services. We strongly encourage the OEB to make a speedy determination in this matter in order to conclude the regulatory process within a reasonable timeline so that construction and operation of the new natural gas services system and services can be provided to our citizens and communities as soon as possible.

If the Board has any questions for Southern Bruce or EPCOR we trust you will allow us the opportunity to provide you with any needed clarifications.

Yours very truly,

Anne Eadie

Paul Eagleson

Mayor Anne Eadie
Municipality of Kincardine

Mayor Mitch Twolan
Township of Huron-Kinloss

Mayor Paul Eagleson
Municipality of Arran-Elderslie

Copy: Stuart Lee, President & CEO
EPCOR

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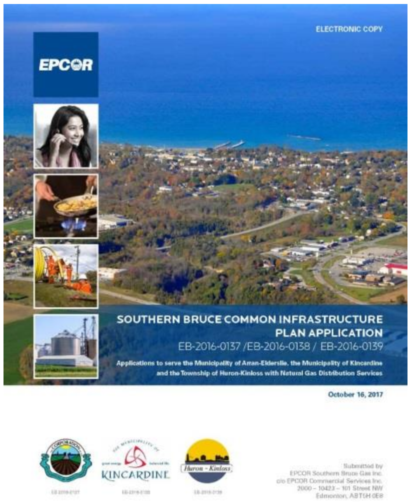
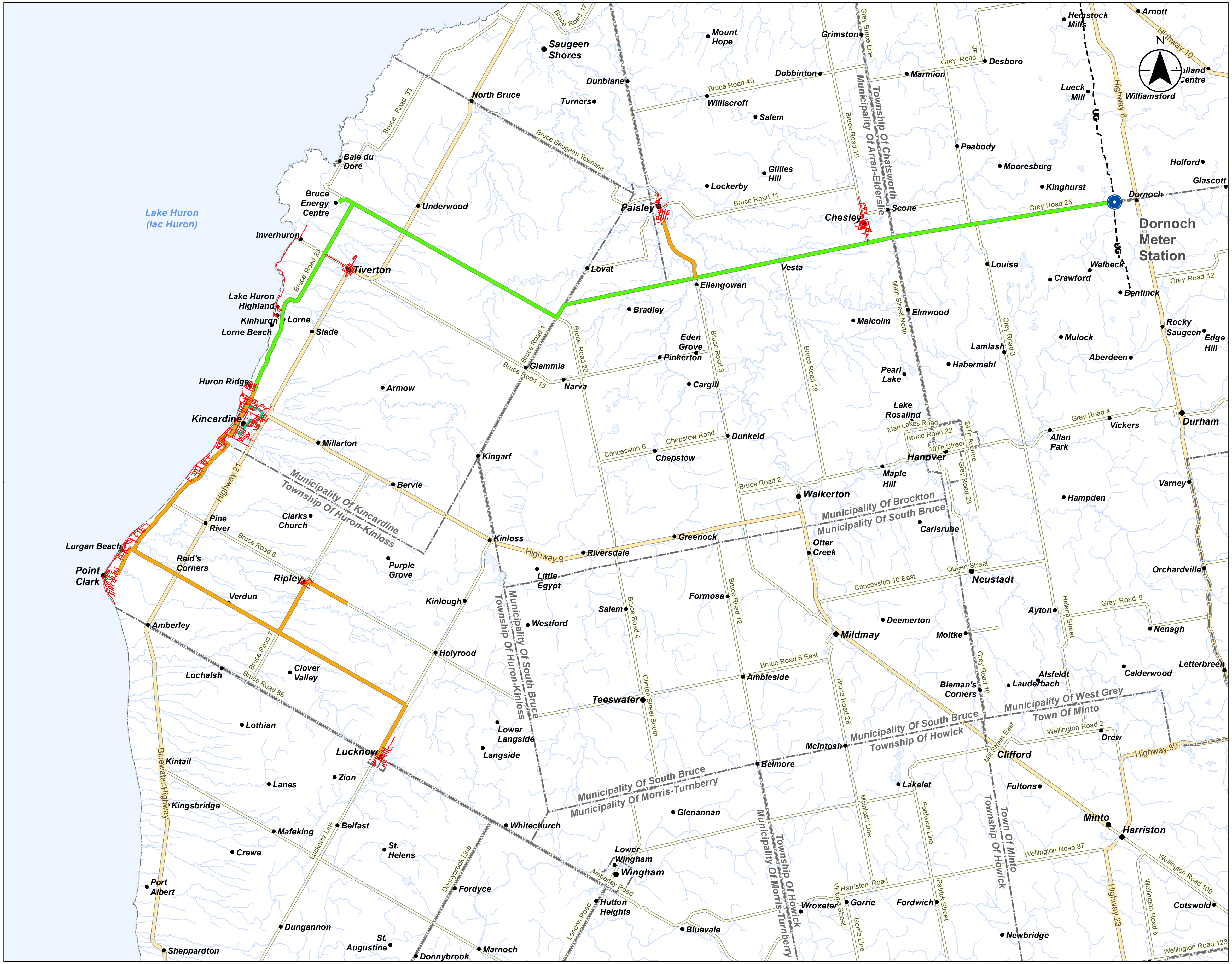


Schedule B

Schedule B
Proposed Natural Gas System Maps



Legend
- Meter Station
- Distribution
- Kincardine Bypass
- Distribution Pressure Mainline System
- High Pressure Mainline Pipeline System
- Expressway / Highway
- Major Road
- -UG- Union Gas Pipeline (Approximately)
- Municipal Boundary - Lower Tier

0 5.5 11 Kilometers
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Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
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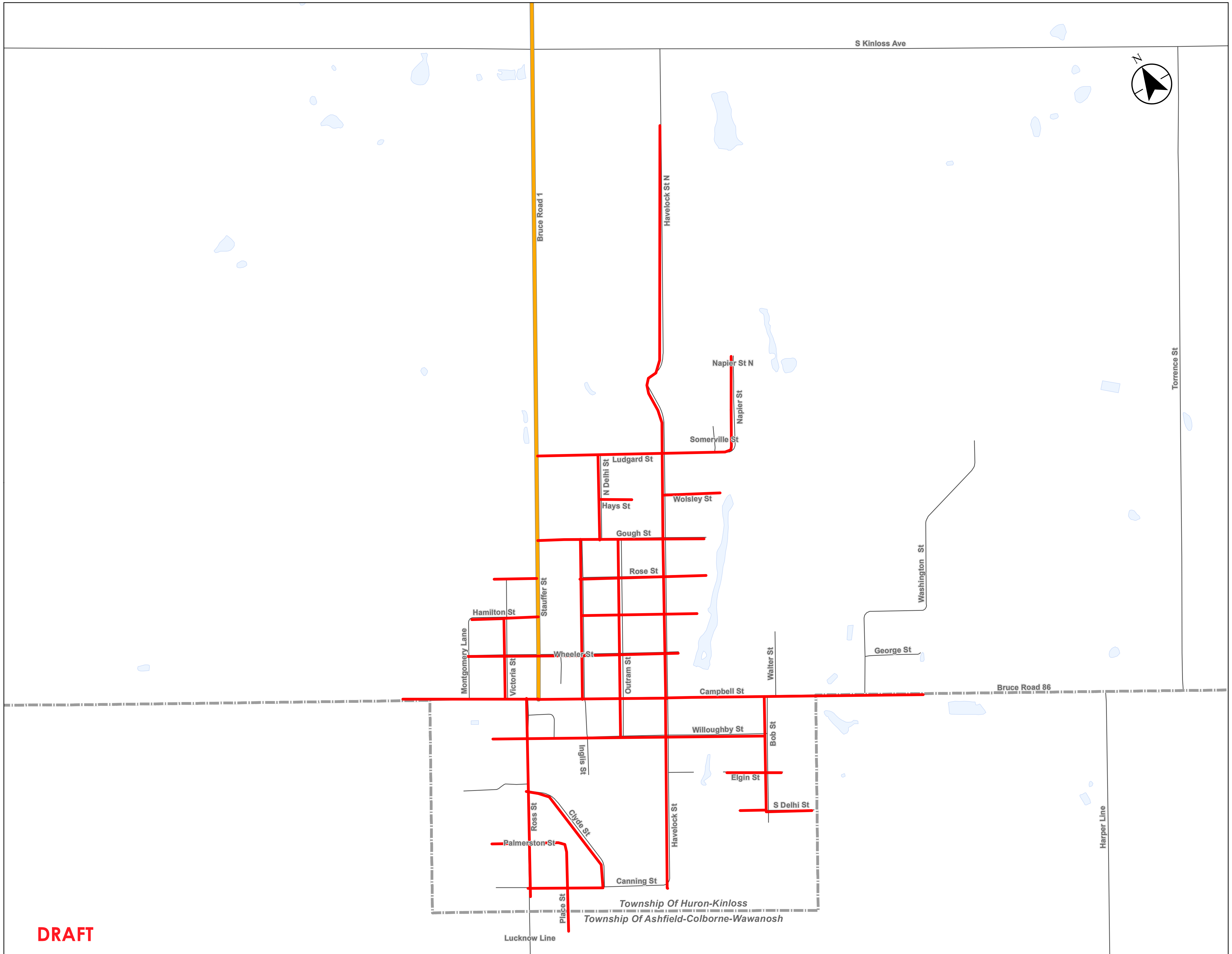
Project Location: Counties Of Bruce, Grey and Huron
160950831
Prepared by SPE on 2017-10-11
Technical Review by BCC on 2017-10-06

Client/Project
EPCOR SOUTHERN BRUCE GAS INC.\NATURAL GAS SERVICE SOUTHERN BRUCE

Figure No.
1-0

Title
Southern Bruce Mainline – Preliminary Preferred Route



Stantec EPCOR

Distribution
Distribution Pressure Mainline System
Road
Watercourse
Municipal Boundary - Lower Tier
Waterbody

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Notes
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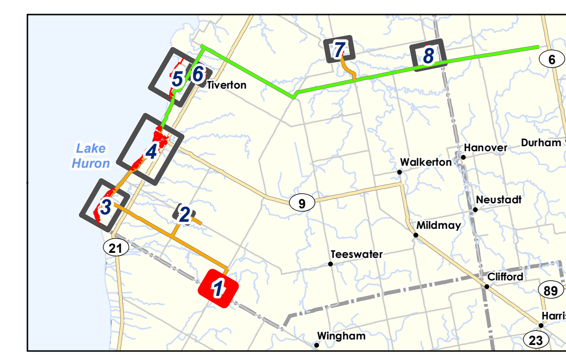

Project Location
Counties Of Bruce, Grey and Huron

160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-1

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Title
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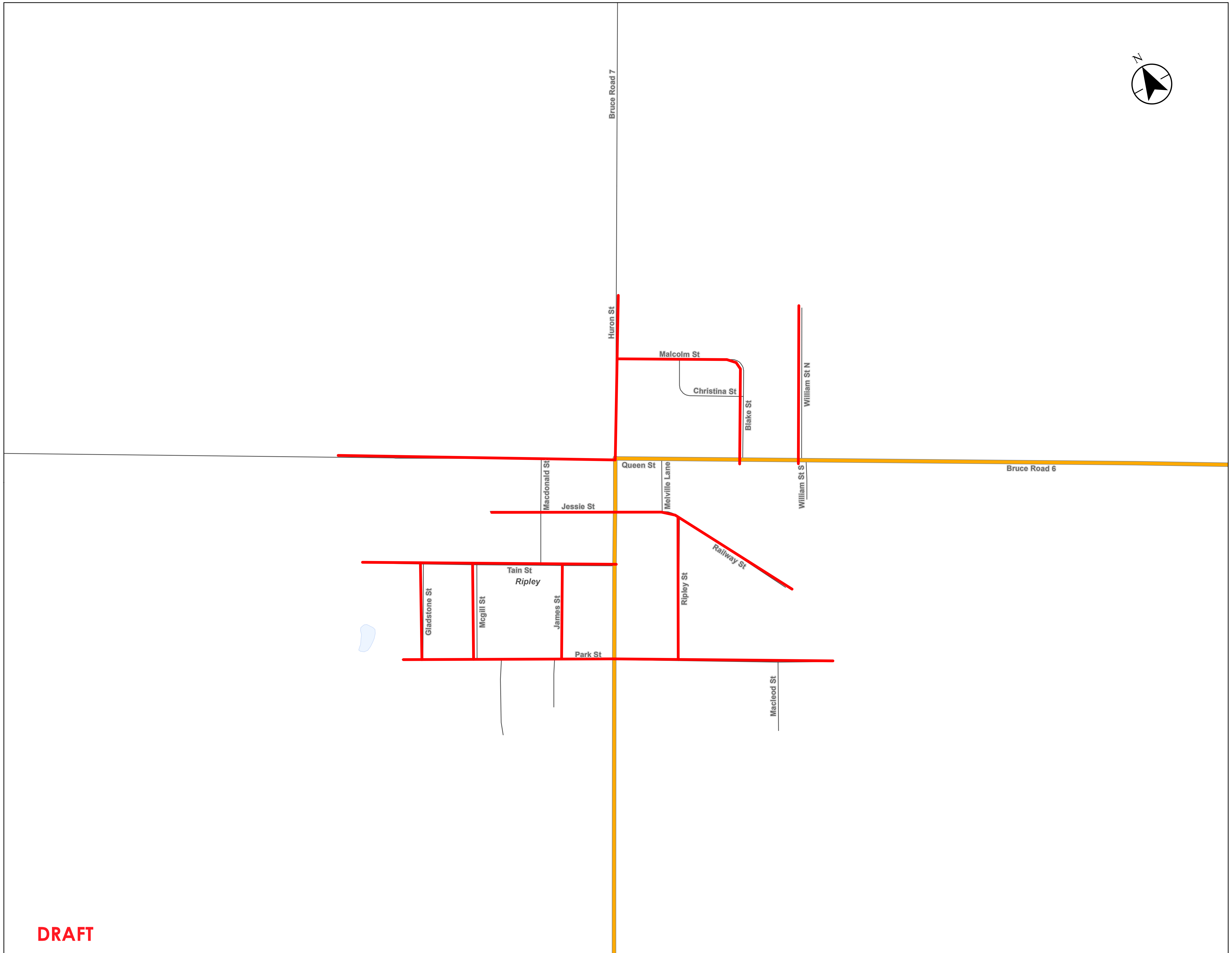

Stantec

EPCOR

Distribution
Distribution Pressure Mainline System
Road
Municipal Boundary - Lower Tier
Waterbody

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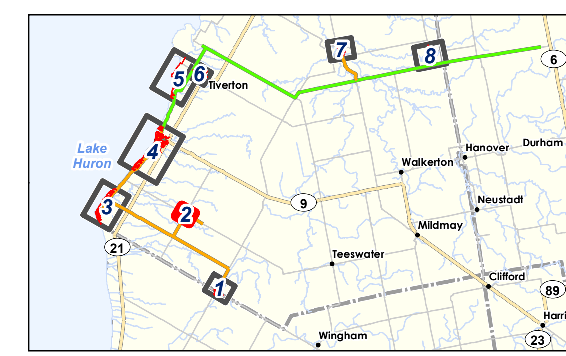

Project Location
Counties Of Bruce, Grey and Huron

160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-2

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Title
Distribution Figures
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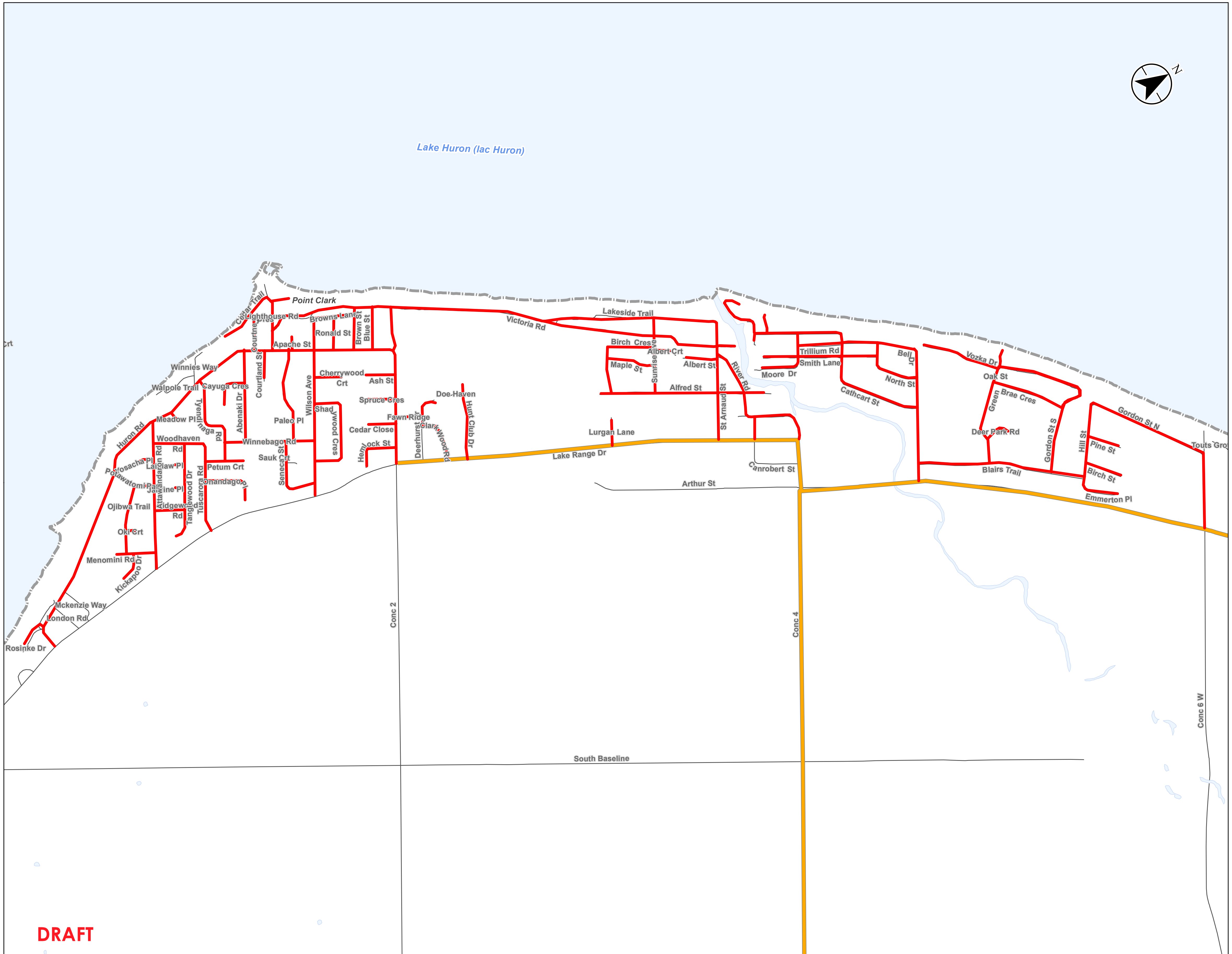

- Distribution
- Distribution Pressure Mainline System
- Road
- Watercourse
- Municipal Boundary - Lower Tier
- Waterbody

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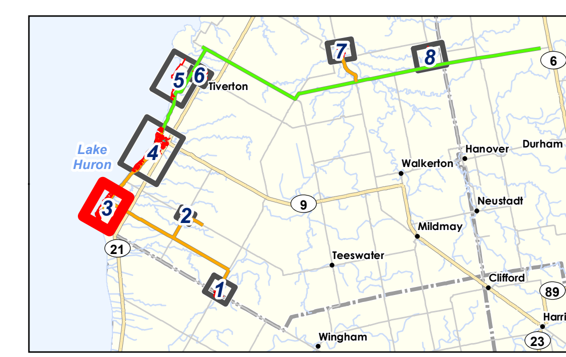


Project Location
Counties Of Bruce, Grey and Huron

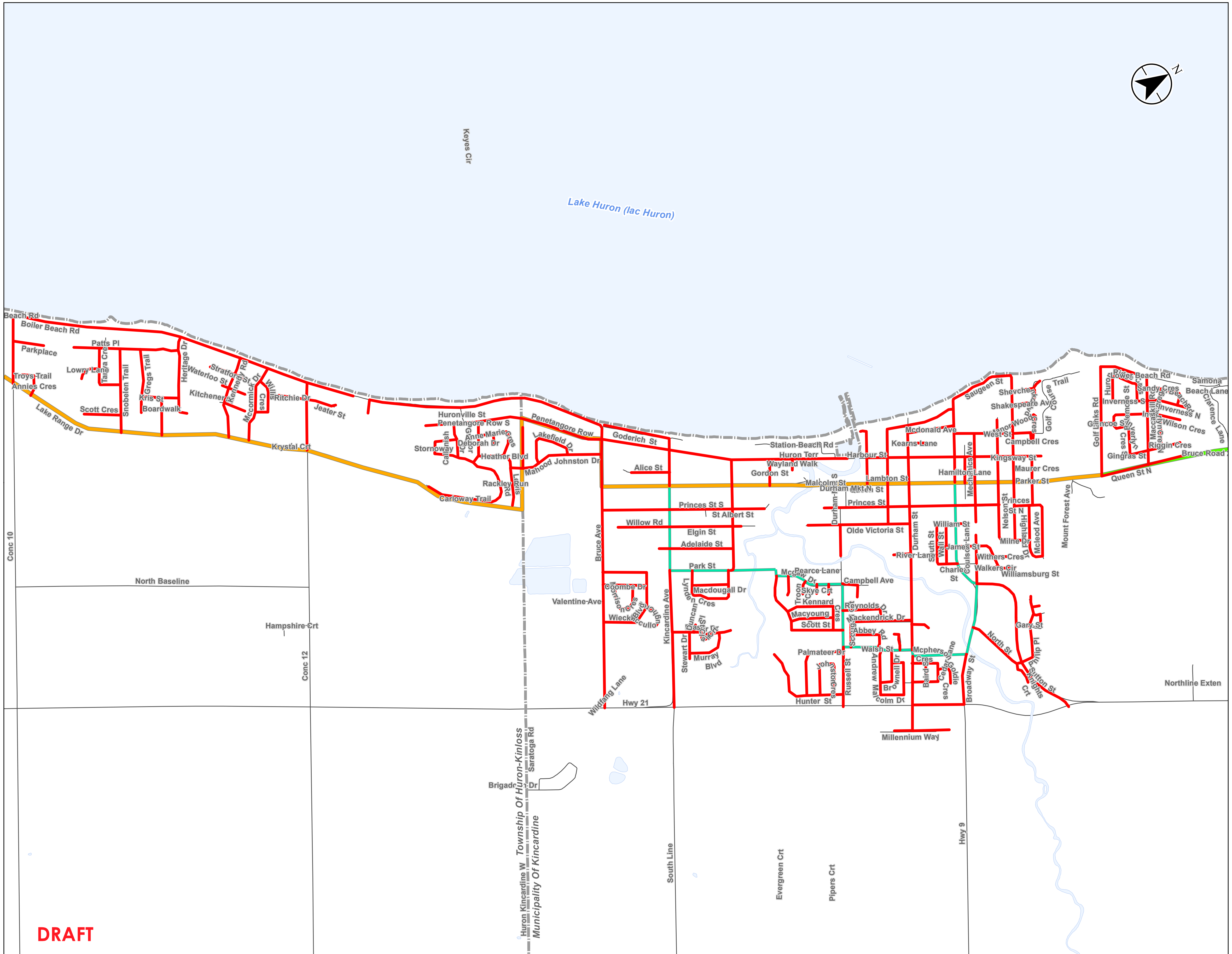
160950831
Prepared by SPE on 2017-10-11

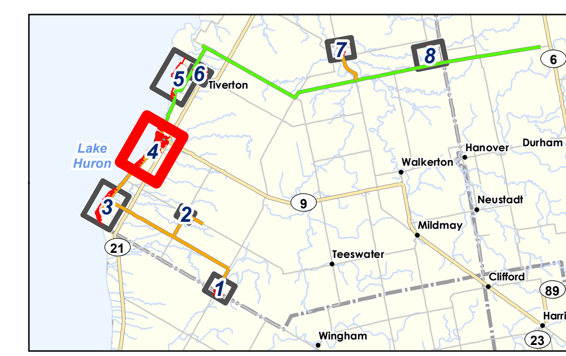
Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-3

DRAFT

Title
Distribution Figures
Lurgan Beach /Point Clarke





Legend

- Distribution
- Kincardine Bypass
- Distribution Pressure Mainline System
- High Pressure Mainline Pipeline System
- Road
- Watercourse
- Municipal Boundary - Lower Tier
- Waterbody

0 540 1,080 metres
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Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources © Queen's Printer for Ontario, 2016. Imagery Date: 2015.

Project Location
Counties Of Bruce, Grey and Huron

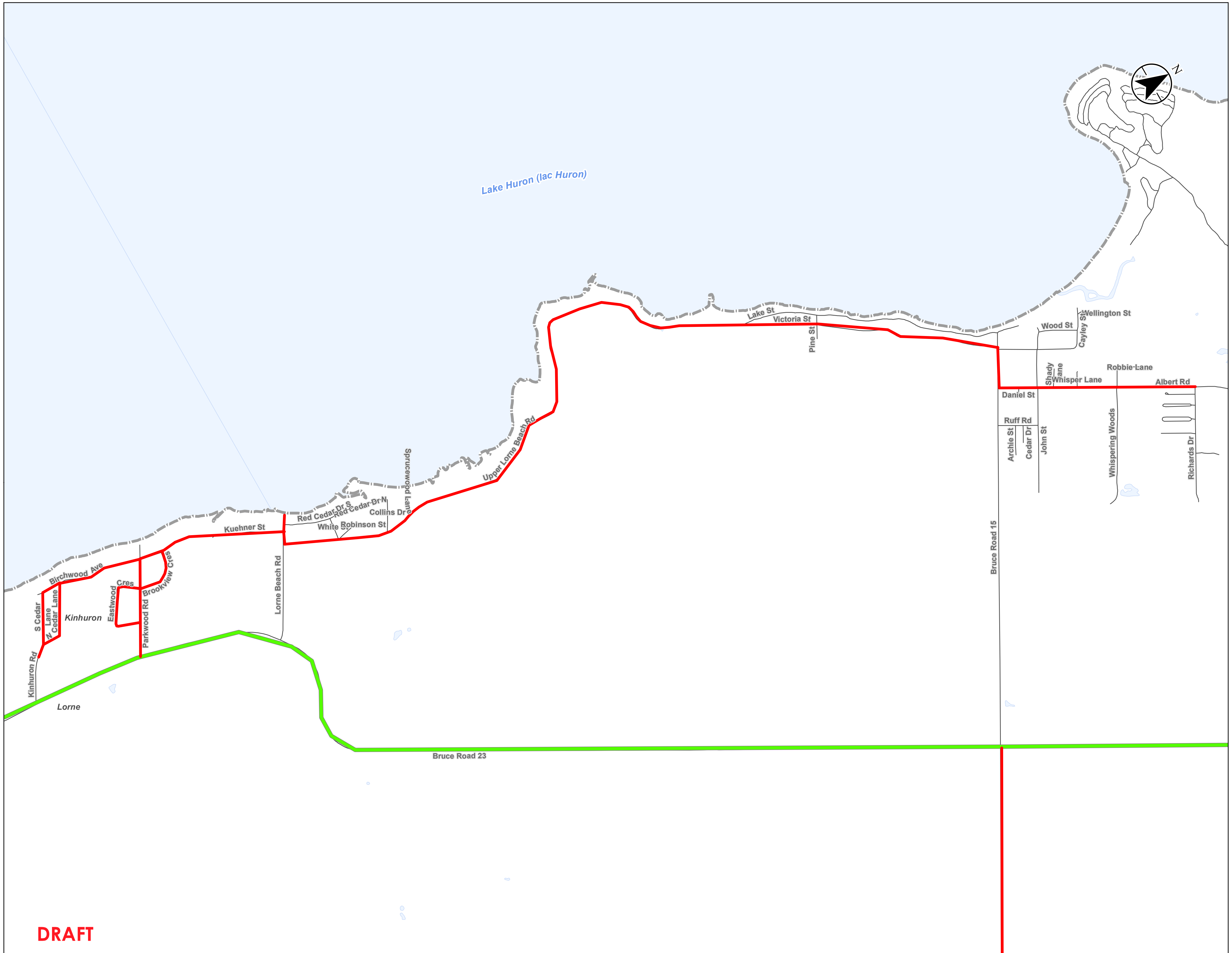
160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-4

DRAFT

Title
Distribution Figures Kincardine



Stantec EPCOR

Distribution
High Pressure Mainline Pipeline System
Road
Watercourse
Municipal Boundary - Lower Tier
Waterbody

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Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
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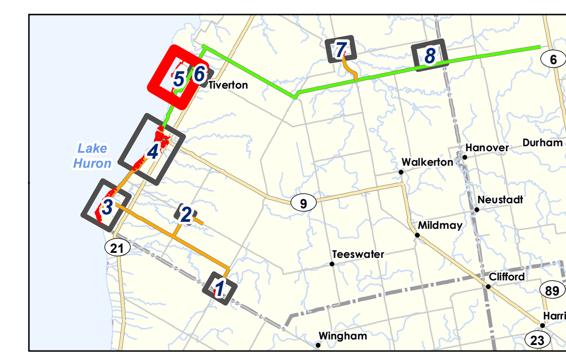
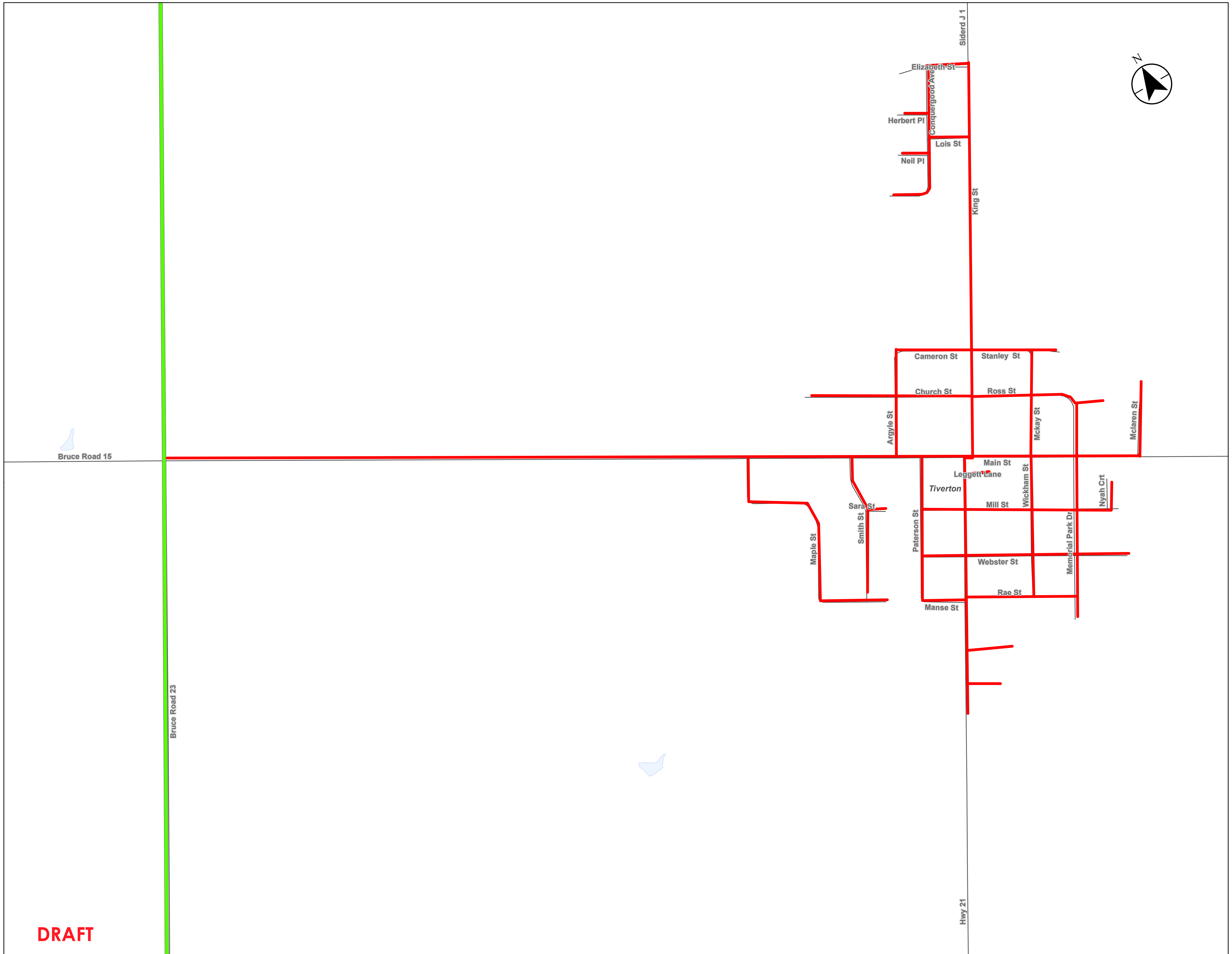


Project Location 160950831
Counties Of Bruce, Grey and Huron
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-5
DRAFT

Title
Distribution Figures
Inverhuron



Stantec
EPCOR

Distribution
High Pressure Mainline Pipeline System
Road
Watercourse
Municipal Boundary - Lower Tier
Waterbody

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Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
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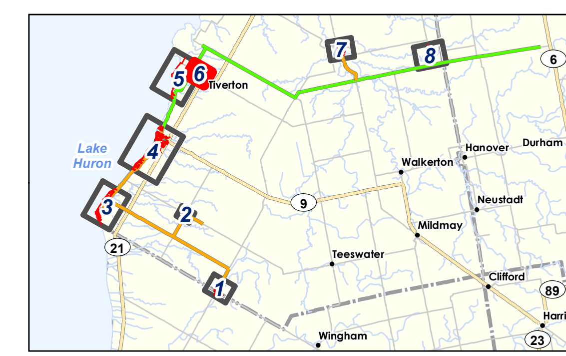


Project Location
Counties Of Bruce, Grey and Huron

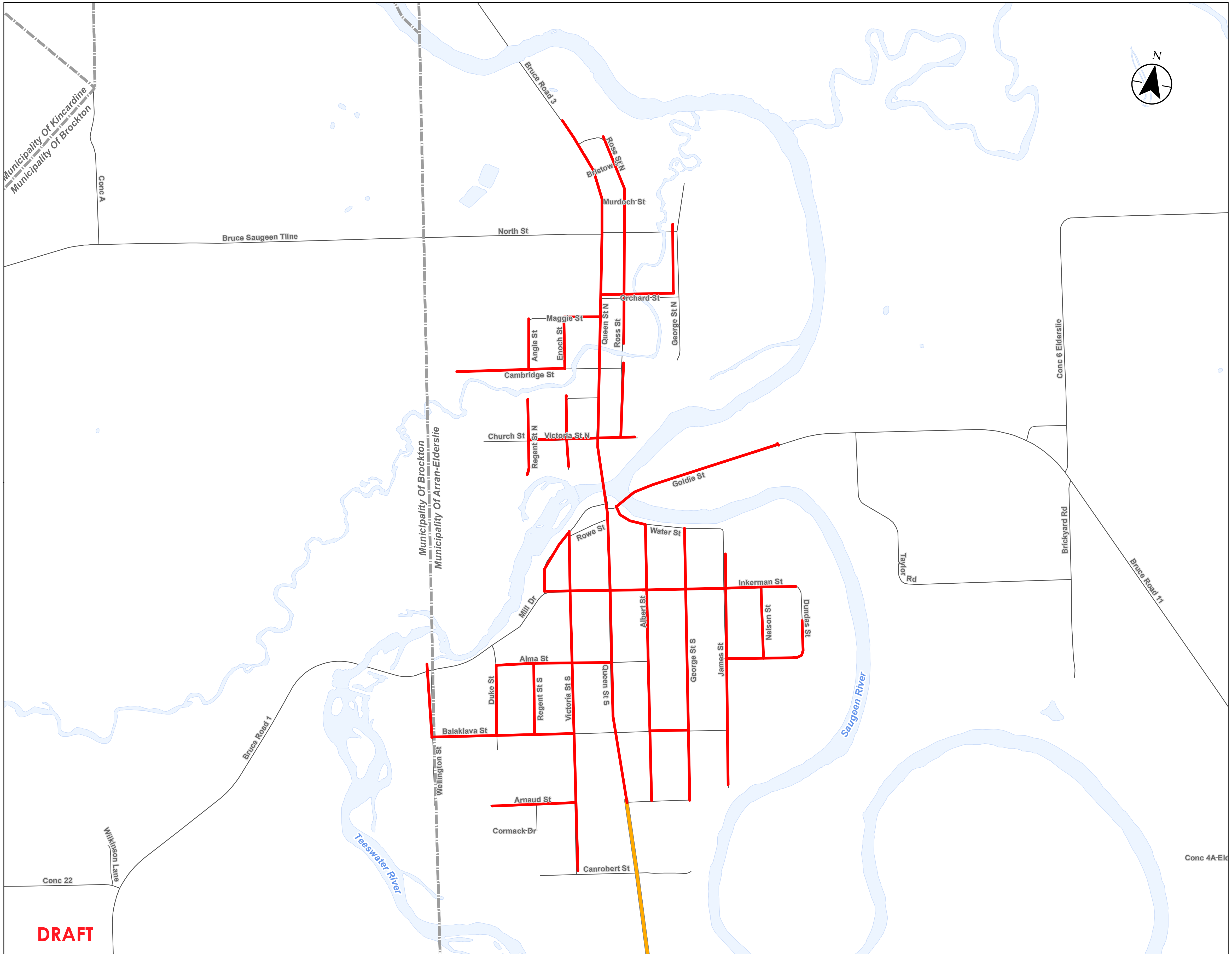
160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-6

DRAFT

Title
Distribution Figures
Tiverton



Stantec

EPCOR

- Distribution
- Distribution Pressure Mainline System
- Road
- Watercourse
- Municipal Boundary - Lower Tier
- Waterbody

0 240 480 metres
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Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
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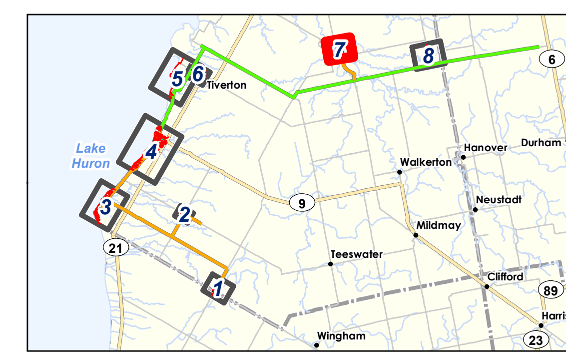

Project Location
Counties Of Bruce, Grey and Huron

160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-7

DRAFT

Title
Distribution Figures
Paisley

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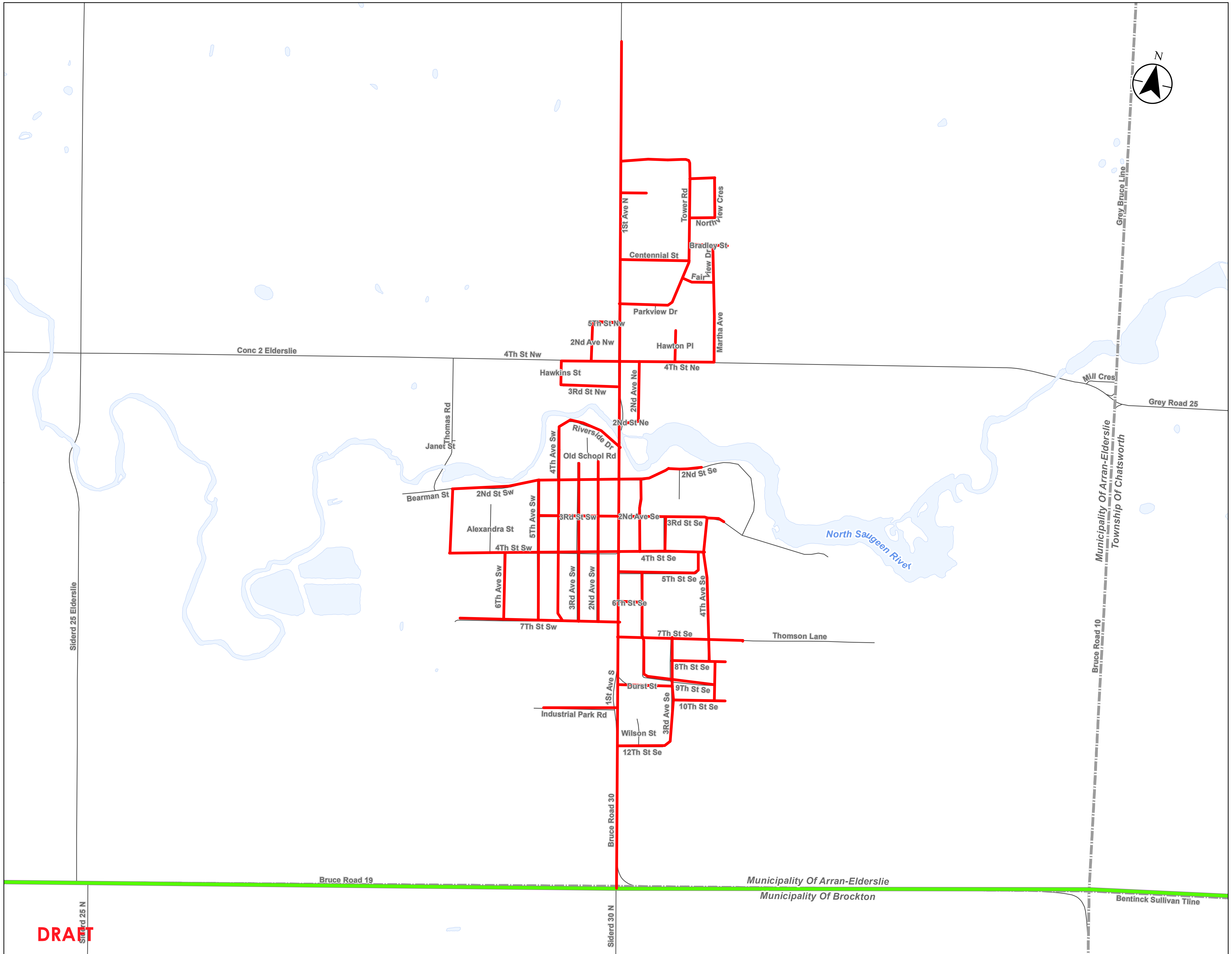

Stantec EPCOR

Distribution
High Pressure Mainline Pipeline System
Road
Watercourse
Municipal Boundary - Lower Tier
Waterbody

0 290 580 metres
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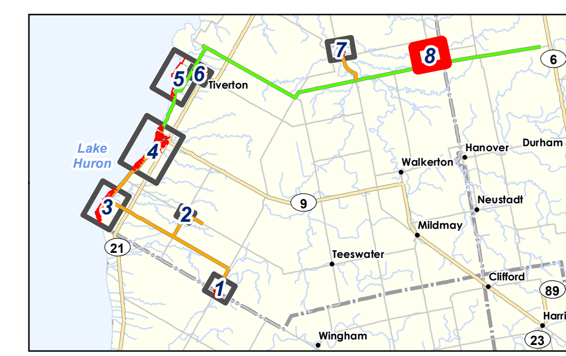
Notes
1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources © Queen's Printer for Ontario, 2016. Imagery Date: 2015.



Project Location
Counties Of Bruce, Grey and Huron

160950831
Prepared by SPE on 2017-10-11

Client/Project
EPCOR UTILITIES INC.
NATURAL GAS SERVICE KINCARDINE

Figure No.
2-8

DRAFT

Title
Distribution Figures
Chesley

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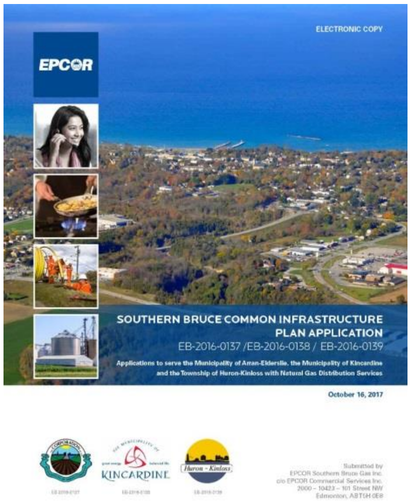

Schedule C
EPCOR/Union Gas
CIP Common Assumptions

October 2, 2017

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

Dear Ms. Walli:

Re: EPCOR Southern Bruce Gas Inc. Applications for Approval of Franchise Agreements and CPCNs, Board File Nos. EB-2016-0137, EB-2016-0138, EB-2016-0139 - CIP Parameters

In Procedural Order No. 8 in the above noted proceeding, the Ontario Energy Board (the "Board") indicated that the proponents had agreed to work together to determine average customer consumption values, and that several Common Infrastructure Plan (CIP) parameters would be used by both proponents in the determination of CIP Comparison Criteria measures. The purpose of this letter is to advise the Board of the details of agreed parameters established by EPCOR and Union Gas.

Customer Consumption[1]

The following annual average consumption values for forecasted mass market customer attachments will be incorporated in the calculation of annual revenue requirements:

Segment/Sub-Segment		Average Annual Consumption (m^3/year)
Residential	Pre-existing homes	2,149
	Future Construction	2,066
Commercial	Small (0-1,500 m3/year)	4,693
	Medium (15,001-50,000 m3/year)	26,933
	Large (>50,000 m^3/year)	75,685
Agricultural	Cash Crop Farm (excl. large grain dryers)	4,720
	Other Agri-Business	4,720

For the above segments, in the year each specific customer attaches, the volume will be 50% of the above figure[2]. Industrial, large grain dryer, and poultry or other similar large farm

[1] EB-2016-0137, 138 and 139 Decision on Preliminary Issues and Procedural Order No. 8, p. 5.
[2] OEB Staff Progress Update to the Board, July 20, 2017, p. 5.

consumption values will vary for each proponent, and their volumes in the year of connection will be based on expected connection timing for those customers.

Depreciation Rates[3]

The following annual depreciation rates, as approved in EB-2011-0210, will be used:

Plant Grouping Code	Description	Book Depreciation Rate[4]
TRANSMISSION PLANT		
46100	Land Rights Not tax deductible (25%) Tax deductible (75%)	1.76%
46200	Structures and Improvements Buildings (Including systems to run buildings)	2.03%
46501	Mains - Metallic	1.98%
46600	Compressor Equipment	3.23%
46700	Measuring and Regulating Equipment	2.60%
DISTRIBUTION PLANT- SOUTHERN OPERATIONS		
47100	Land Rights	1.65%
47200	Structures and Improvements Buildings (Including systems to run buildings)	2.22%
47301	Services - Metallic	2.81%
47302	Services - Plastic	2.51%
47400	Regulators	5.00%
47401	Regulator and Meter Installations	2.80%
47501	Mains - Metallic	2.83%
47502	Mains - Plastic	2.31%
47700	Measuring and Regulating Equipment	3.66%
47800	Meters	3.82%

Inflation Costs[5]

For purposes of CIP comparison, both proponents will apply the most recent four quarter average annual inflation rate as determined from GDP IPI FDD, which is 1.27% as reported for the second quarter of 2017.

[3] EB-2016-0137, 138 and 139 Decision on Preliminary Issues and Procedural Order No. 8, p. 5.
[4] Depreciation rates per Union Gas 2013 Rate Case Evidence (EB-2011-0210) – Exhibit D3,Tab 4, Schedule 1.
[5] EB-2016-0137, 138 and 139 Decision on Preliminary Issues and Procedural Order No. 8, p. 8.

Net Present Value of Gross Revenue Requirement[6]

The Board indicated that it would be assisted in seeing the net present value of the gross revenue requirement for each CIP proposal, but also indicated that the costs of debt and return on equity, which are commonly used to establish a discount rate to determine net present value, are not expected to be provided in the proponents CIP submissions[7]. For this reason the proponents have agreed to apply a common discount rate of 4%, which is commonly used as a proxy for a "real" discount rate in DSM and CDM Cost Effectiveness Tests[8].

Corporate Tax Rate[9]

Both proponents will apply a corporate income tax rate of 26.5%, which is the sum of 15% federal tax rate and 11.5% Ontario provincial tax rate.

Prescribed Interest Rate[10]

For the purpose of calculating interest during construction, both proponents will use 2.99%, which is OEB's Construction Work in Progress ("CWIP") account prescribed interest rate for Q4, 2017.

Both proponents have agreed upon the above values and will apply them in their respective CIP proposals.

Yours truly,

Karen Hockin, P. Eng.
Manager, Regulatory Initiatives
Union Gas Ltd.

Bruce Brandell
Director of Commercial Services
EPCOR Southern Bruce Gas Inc.

Cc: Charles Keizer, Torys
Mark Kitchen, Union
Richard King, Osler
Britt Tan, EPCOR Utilities Inc.

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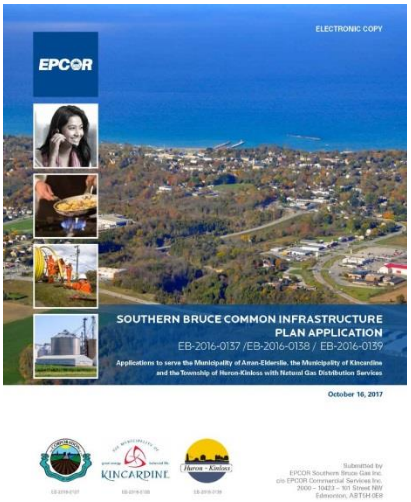
[6] Ibid, p. 8.
[7] Ibid, p. 6.
[8] EB-2014-0134 Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 35.
[9] *Corporation Tax Rates*, Government of Canada - Revenue Agency, 7 February 2017. Web. 14 September 2017 https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/corporation-tax-rates.html
[10] *Prescribed Interest Rates*, Ontario Energy Board, 15 September 2017. Web. 15 September 2017 https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates



Schedule D

Schedule D
Customer and Volume Demands

Schedule D

Table D1 - Customer Connections

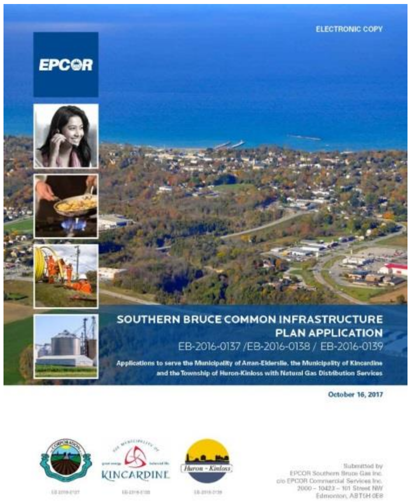
Customer Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total Available Market
Existing Residential	861	2,297	3,237	3,742	4,176	4,349	4,349	4,349	4,349	4,349	7,250
New Residential	46	103	159	215	271	328	384	424	462	469	781
Sub Total	**907**	**2,400**	**3,396**	**3,957**	**4,447**	**4,677**	**4,733**	**4,773**	**4,811**	**4,818**	**8,031**
Small Commercial	55	144	215	288	343	359	359	359	359	359	554
Medium Commercial	10	27	43	59	67	69	69	69	69	69	107
Large Commercial	3	7	13	16	17	19	19	19	19	19	28
Sub Total	**68**	**178**	**271**	**363**	**427**	**447**	**447**	**447**	**447**	**447**	**688**
Small Agricultural	-	-	-	1	2	2	2	2	2	2	7
Industrial and Large Agricultural	4	5	9	11	11	11	11	11	11	11	13
Sub Total	**4**	**5**	**9**	**12**	**13**	**13**	**13**	**13**	**13**	**13**	**20**
Grand Total	**979**	**2,583**	**3,676**	**4,332**	**4,887**	**5,137**	**5,193**	**5,233**	**5,271**	**5,278**	**8,739**

Table D2- Average Volume

Customer Type (m^3/yr)	Average Volume
Existing Residential	2,149
New Residential	2,066
Small Commercial	4,693
Medium Commercial	26,933
Large Commercial	75,685
Small Agricultural	4,720
Industrial and Large Agricultural	Individual

Table D3 - Volumes

Customer Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total Available Market
Existing Residential (m^3)	925,145	3,393,271	5,946,283	7,498,936	8,507,891	9,160,113	9,346,001	9,346,001	9,346,001	9,346,001	15,580,250
New Residential (m^3)	47,518	153,917	270,646	386,342	502,038	618,767	735,496	834,664	915,238	961,723	1,613,546
Sub Total	**972,663**	**3,547,188**	**6,216,929**	**7,885,278**	**9,009,929**	**9,778,880**	**10,081,497**	**10,180,665**	**10,261,239**	**10,307,724**	**17,193,796**
Small Commercial (m^3)	129,058	466,954	842,394	1,180,290	1,480,642	1,647,243	1,684,787	1,684,787	1,684,787	1,684,787	2,599,077
Medium Commercial (m^3)	134,665	498,261	942,655	1,373,583	1,696,779	1,831,444	1,858,377	1,858,377	1,858,377	1,858,377	2,869,550
Large Commercial (m^3)	113,528	378,425	756,850	1,097,433	1,248,803	1,362,330	1,438,015	1,438,015	1,438,015	1,438,015	2,091,631
Sub Total	**377,250**	**1,343,639**	**2,541,899**	**3,651,305**	**4,426,223**	**4,841,017**	**4,981,179**	**4,981,179**	**4,981,179**	**4,981,179**	**7,560,257**
Small Agricultural (m^3)	-	-	-	2,360	7,080	9,440	9,440	9,440	9,440	9,440	33,040
Industrial and Large Agricultural (m^3)	5,626,889	33,095,244	33,548,693	34,177,652	34,363,734	34,363,734	34,363,734	34,363,734	34,363,734	34,363,734	34,942,066
Sub Total	**5,626,889**	**33,095,244**	**33,548,693**	**34,180,012**	**34,370,814**	**34,373,174**	**34,373,174**	**34,373,174**	**34,373,174**	**34,373,174**	**34,975,106**
Grand Total	**6,976,802**	**37,986,071**	**42,307,521**	**45,716,594**	**47,806,966**	**48,993,071**	**49,435,850**	**49,535,018**	**49,615,592**	**49,662,077**	**59,729,159**



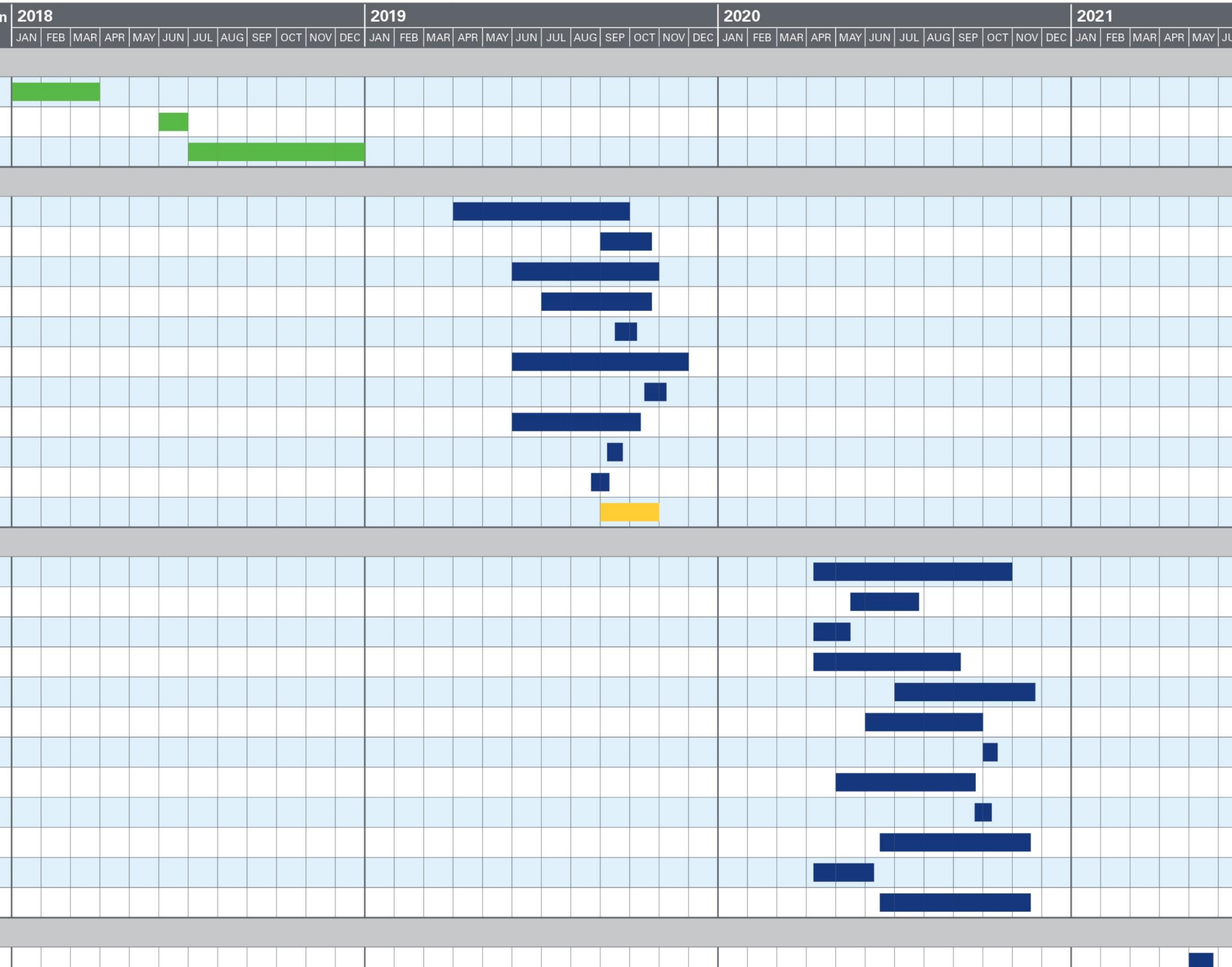
Schedule E

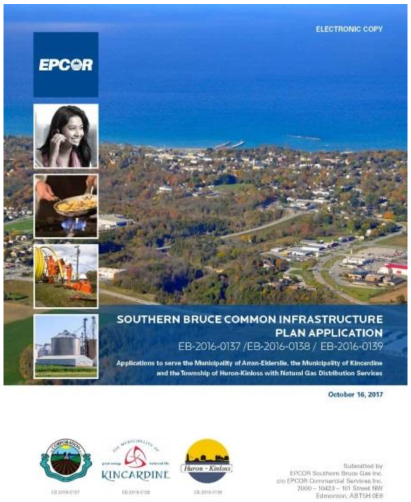
Schedule E
Construction Schedule

Schedule E

Construction Schedule

Task	Length (km)	Duration (days)
2018 - Leave to Construct Application		
Conclude Environmental Report		
Submit LTC Application		
LTC Approval		
2019 - Commencement of Construction – Dornoch to Kincardine		
NPS 8 steel Dornoch to Bruce Energy Center	58.6	131
Dornoch Check Meter Station		40
NPS 6 steel from Bruce Energy Center to Kincardine	15.8	110
NPS 2 plastic distribution in Tiverton	10.8	80
Tiverton Pressure Regulating Station		15
NPS 2 plastic distribution in Kincardine	66.8	130
Kincardine Pressure Regulating Stations		15
NPS 6 plastic heading south along shore	7.1	90
Bruce Energy Centre Sales Meter Station		10
GFSA Sales Meter Station		10
Connection to Union Gas System		
2020 - Construction – Kincardine to Lucknow		
NPS 6 plastic from Kincardine to Lucknow	36.6	150
NPS 2 plastic distribution in Ripley	6.4	48
NPS 4 plastic to Ripley	7.3	30
NPS 2 plastic distribution in Lucknow	11.6	110
NPS 4 & 2 plastic distribution in Inverhuron	12.1	100
NPS 2 plastic distribution in Paisley	11.9	90
Paisley Pressure Regulating Station		10
NPS 2 plastic distribution in Chesley	17.9	105
Chesley Pressure Regulating Station		10
NPS 2 plastic distribution in Point Clark	15.7	110
NPS 4 plastic from Lurgan Beach to Point Clark	2.1	45
NPS 2 plastic distribution in Lurgan Beach	15.0	110
2021 - Completion of all Construction		
Grain Dryer		15

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EPCOR

SOUTHERN BRUCE COMMON INFRASTRUCTURE PLAN APPLICATION

EB-2016-0137 /EB-2016-0138 / EB-2016-0139

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with Natural Gas Distribution Services

October 16, 2017

Submitted by
EPCOR Southern Bruce Gas Inc.
c/o EPCOR Commercial Services Inc.
2000 – 10423 – 101 Street NW
Edmonton, AB T5H 0E8

Schedule F
EPCOR 2016 Annual Information Form

PROVIDING MORE

EPCOR UTILITIES INC.

2016
ANNUAL
INFORMATION
FORM

March 2, 2017

TABLE OF CONTENTS

PRESENTATION OF INFORMATION

This Annual Information Form (AIF) provides material information about the business and operations of EPCOR Utilities Inc. (EUI, EPCOR or the Corporation). Any reference to EPCOR or the Corporation in this AIF means EPCOR Utilities Inc. and its subsidiaries on a consolidated basis, except where otherwise noted or the context otherwise indicates. In this document, Capital Power refers to Capital Power Corporation and its directly and indirectly owned subsidiaries including Capital Power L.P., except where otherwise noted or the context otherwise indicates.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2016. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information for the year ended December 31, 2016 is presented in accordance with the International Financial Reporting Standards that were adopted by EPCOR as Canadian generally accepted accounting principles (GAAP) on January 1, 2011, except where otherwise noted.

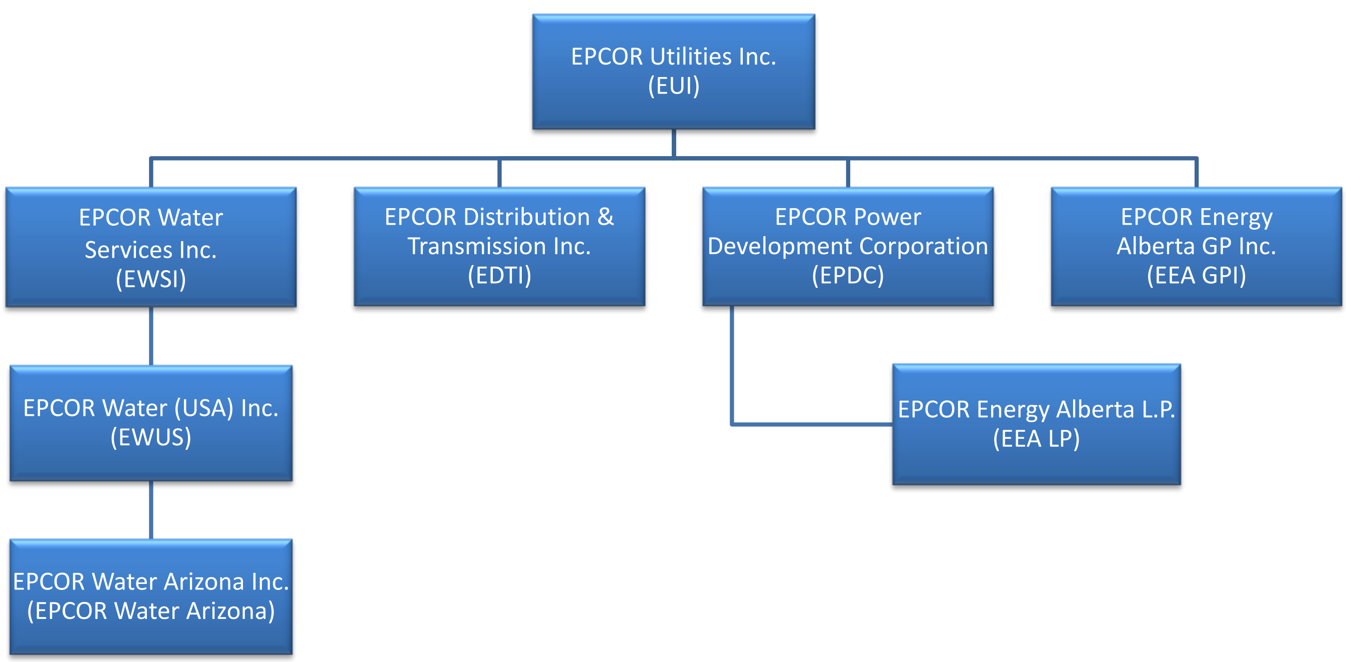
The Corporation's Management Discussion and Analysis (MD&A) dated March 2, 2017 for the year ended December 31, 2016 and the Corporation's Audited Consolidated Financial Statements for the year ended December 31, 2016 provide additional information. Copies of these documents are available on SEDAR at www.sedar.com or through the Corporation's website, www.epcor.com.

CORPORATE STRUCTURE

EPCOR Utilities Inc. was incorporated as Edmonton Power Corporation pursuant to the *Business Corporations Act* (Alberta) on August 28, 1995. On May 8, 1996, Edmonton Power Corporation changed its name to EPCOR Utilities Inc. and, on May 26, 1999, the Corporation amended its Articles of Incorporation to delete the provision restricting the Corporation from offering its securities to the public. The City of Edmonton (the City or the Shareholder) is the sole common shareholder of the Corporation.

The principal business office and registered office of the Corporation is located at 2000, 10423 – 101 Street NW, Edmonton, Alberta, Canada, T5H 0E8.

The following organization chart indicates the inter-corporate relationships of the Corporation and its material subsidiaries as of the date of this AIF:



All common voting shares of all material subsidiaries of the Corporation shown above are owned by EPCOR, either directly or indirectly. All material wholly-owned subsidiaries are incorporated or formed in Alberta, except for EWUS, which is incorporated in Delaware and is qualified to carry on business in the states of Arizona, New

Mexico and Texas, and EPCOR Water Arizona, which is incorporated in Arizona and is qualified to carry on business in the state of Arizona.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

In May 2014, the Corporation began offering consumer electricity and natural gas contracts in Alberta under the “Encor” brand.

Also in May 2014, an EPCOR led consortium won a public-private partnership bid to design, build and finance significant additions to an existing wastewater treatment plant in the city of Regina, Saskatchewan and to operate and maintain the plant for a term of 30 years. In August 2014, EPCOR took over operations of the existing wastewater treatment plant. Substantial completion of the newly constructed additions was reached in December 2016, with final completion expected in the second quarter of 2017.

In June 2014, the Alberta Utilities Commission (AUC) approved the application to partition the assets of the Heartland Transmission Project, a double-circuit 500 kilovolt (kV) transmission line enhancing the transmission system between the south Edmonton area and the Industrial Heartland region near Fort Saskatchewan, which was, until that time, jointly owned by EPCOR, through its subsidiary EDTI, and AltaLink L.P. The partition, according to the service territories of the respective owners, was completed on September 30, 2014.

In April 2015, EPCOR exchanged 9,450,000 limited partnership units for an equal number of common shares of Capital Power which were immediately sold at an offering price of $23.85 per share for aggregate gross proceeds of $225 million. In addition, EPCOR exchanged all of its remaining 9,391,000 exchangeable limited partnership units for common shares of Capital Power. The sale reduced the Corporation’s remaining interest in Capital Power to below 10%. In 2016 and early 2017, the Corporation sold its remaining shares in Capital Power.

In September 2015, David Stevens retired as President and Chief Executive Officer of EPCOR. In September 2015, Stuart Lee returned to EPCOR and assumed the responsibilities of President and Chief Executive Officer. Mr. Lee was Vice President and Corporate Controller of EPCOR prior to moving to Capital Power in 2009.

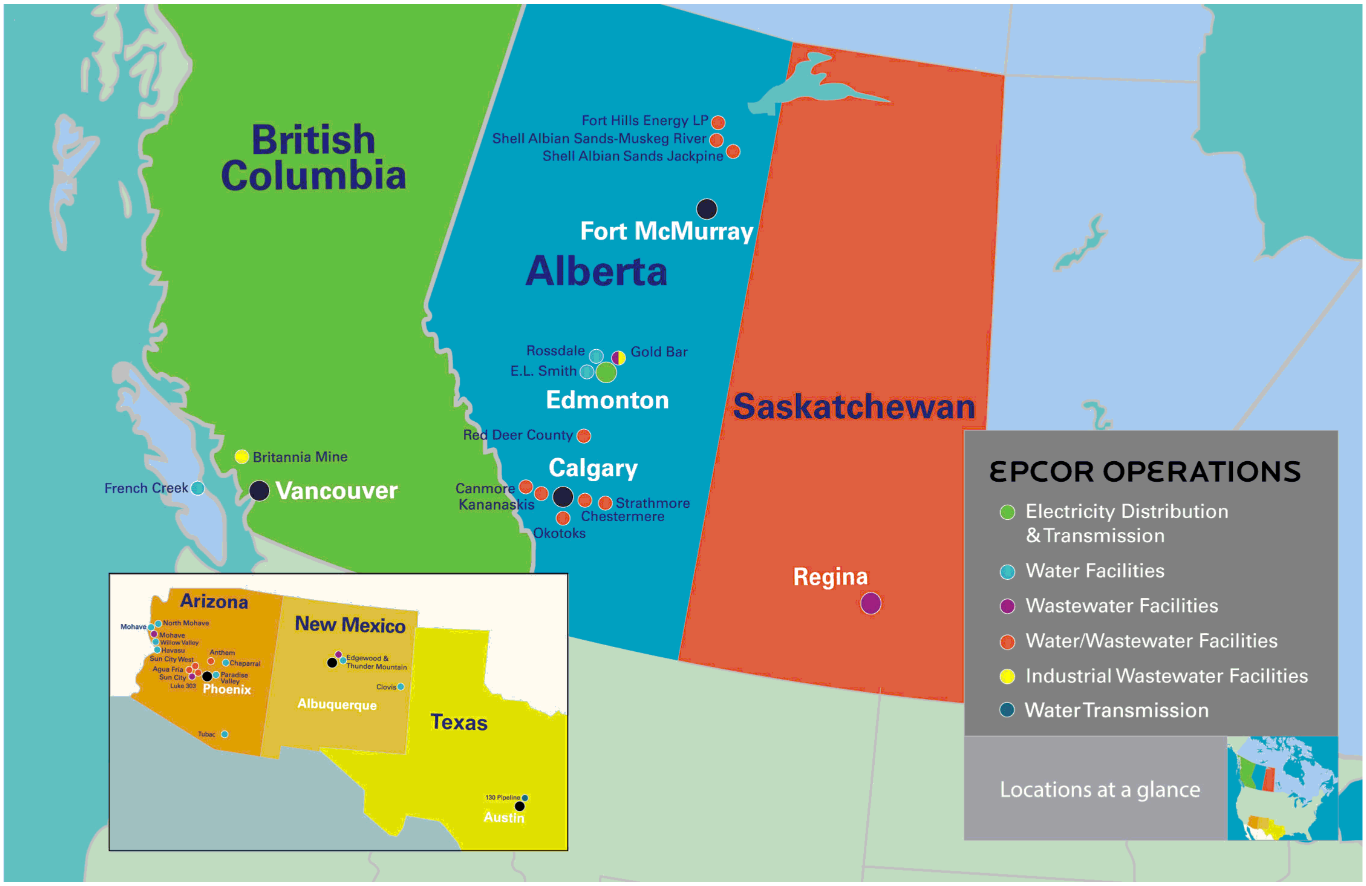
Commencing in 2009, EPCOR owned and operated potable water and domestic wastewater facilities under certain leasing, financing and operating agreements with Suncor Energy Oilsands Limited Partnership (Suncor). This included facilities at the Steepbank, Firebag, Borealis and Voyageur sites north of Fort McMurray, Alberta. On February 18, 2015, Suncor gave the Corporation notice that it was exercising its contractual rights to buy back the leased assets and terminate the related financing and operating agreements. Several operated facilities were transferred back to Suncor during 2015 and the transfer of the remaining owned and operated facilities and operations was completed in August 2016. The transfers did not have a material impact on the Corporation or its operations.

In August 2016, a United States (U.S.) subsidiary of EPCOR acquired a water transmission pipeline, groundwater well production assets, long-term wholesale water supply contracts and other related agreements (collectively the EPCOR 130 Pipeline) for approximately USD $71 million, including future payments on contingent on growth. Untreated groundwater is sold and distributed to four municipalities in Travis County, Texas under long-term wholesale supply contracts with terms ranging from 25 years to 50 years. Under the four existing contracts, approximately 40% of the pipeline’s design capacity is utilized. The unutilized design capacity will support growth with the addition of new wholesale water supply customers, over time.

BUSINESS OF EPCOR

The Corporation, through wholly-owned subsidiaries, builds, owns and operates electrical transmission and distribution networks, water and wastewater facilities and infrastructure in Canada and the U.S. and provides Rate Regulated Option (RRO) and default supply electricity related services and also sells electricity and natural gas to Alberta residential consumers under contracts through its Encor brand. EPCOR operates its business under the Water Services, Distribution and Transmission, Energy Services and Corporate business segments. The Corporation operates in Canada and the Southwestern U.S.

The map below shows the geographies in which the Corporation has material operations.



WATER SERVICES

EPCOR's Water Services business segment which is conducted through EWSI and its various subsidiaries including EWUS in the U.S., provides water purification and distribution and wastewater treatment services within Edmonton as well as water and wastewater collection and treatment services including design, build, finance, operate and maintain services to municipal and industrial customers in several other communities in Western Canada. In addition, EPCOR provides water purification, distribution, transmission and wastewater collection and treatment services in the Southwestern U.S.

EPCOR's Water Services business segment's primary objective is to reliably supply sufficient drinking water, industrial process water and untreated ground water, and to collect and treat wastewater while ensuring that the quality exceeds public health, environmental and industrial requirements.

Facilities

EPCOR owns three and operates 14 other water treatment and / or distribution facilities in Alberta and British Columbia. Additionally, EPCOR owns one wastewater treatment facility and operates 18 other wastewater treatment and / or collection facilities in Alberta, British Columbia and Saskatchewan.

Through its wholly-owned subsidiaries, EPCOR Water Arizona, Chaparral City Water Company (Chaparral), EPCOR Water New Mexico, Inc. (EPCOR Water New Mexico), and EPCOR 130 Project Inc. and 130 Regional Water Supply Corporation (together EPCOR 130), EWUS operates in 14 water utility districts containing one or more water treatment and / or distribution facilities, and six wastewater utility districts containing one or more wastewater treatment and / or collection facilities. The water and wastewater utility districts consist of developer-built communities within a number of municipalities in Arizona and New Mexico.

In Texas, the EPCOR 130 Pipeline distributes water to contracted wholesale customers in central Texas through an 85 kilometre, 30-inch pipeline that carries water from the well field to a termination point near the City of Manor and includes pump stations and storage tanks. EPCOR 130 provides water under four existing water supply contracts with municipal customers. These wholesale water contracts are subject to Texas Public Utilities Commission appellate review, however, to date they have not been reviewed.

Facilities Owned and Operated by EPCOR

EPCOR's facilities in Edmonton encompass two water treatment plants, a wastewater treatment plant and a potable water distribution network with approximately 4,000 kilometres of distribution and transmission mains and approximately 20,200 hydrants and 64,800 valves. Its 12 reservoir sites have an aggregate capacity of approximately 800 million litres.

The Rossdale water treatment plant, located in central Edmonton, was first commissioned in 1947. The E.L. Smith water treatment plant, located in southwest Edmonton, upstream of the Edmonton downtown core, was commissioned in 1976. Through improvements and optimization of treatment processes at E.L. Smith and Rossdale (including coagulation optimization and ultraviolet (UV)), water production capabilities at these plants have increased to keep pace with growing demand.

The following table provides volume details of the two owned water treatment plants in Edmonton:

Plant	**Plant Production Capacity** (1) (millions of litres per day)
Rossdale	280
E.L. Smith	400
Total	680

(1) Plant production capacity represents the amount of treated water that can be produced under maximum warm conditions with no plant shutdowns or detrimental raw water quality conditions such as run-off. Actual production varies with seasonality, raw water conditions and customer demand.

The water source for EPCOR owned water treatment plants in Edmonton is the North Saskatchewan River. EPCOR has withdrawal licenses to remove up to 558 million litres of water per day or about 3% to 4% of the daily average flow along the North Saskatchewan River.

EPCOR uses a number of advanced technologies in its operations, including remote water plant operations and the use of geospatial information technology to operate and maintain its water distribution system in Edmonton. EPCOR utilizes UV treatment at its E.L. Smith and Rossdale plants in Edmonton and at its White Tanks water treatment plant in Arizona. UV treatment provides an additional barrier against protozoa contaminating drinking water and enhances the drinking water quality within these regions. EPCOR has made proactive process and procedural changes to remove chlorine from controllable waste streams that are returned to the North Saskatchewan River from EPCOR water treatment plants. When winter conditions are stable, the two water treatment plants in Edmonton have, since 2009, been practicing direct filtration, which reduces the amount of chemicals and solids that are returned to the North Saskatchewan River.

EPCOR continues to improve the underground water distribution infrastructure within Edmonton through the annual water main replacement program, which was started in 1986 and originally targeted cast iron water main replacement. In 2016, approximately 16 kilometres of water mains, including 11 kilometres of cast iron water mains, were replaced at a total cost of $36 million. Of the 1,220 kilometres of cast iron water mains originally installed, 591 kilometres remain in service. EPCOR's efforts have been instrumental in reducing future water infrastructure replacement costs within Edmonton as well as reducing the total number of annual water main breaks. In 1986, prior to EPCOR's replacement programs, the annual number of water main breaks peaked at 1,600. In 2016, there were 242 breaks, well below the annual performance target of 574.

Prior to 1950, lead, which is a contaminant, was one of the materials used to make water service lines. While responsibility for water service lines is shared between the homeowner and the Corporation, the Corporation proactively manages the issue of lead contamination in drinking water obtained through lead water service lines in its Edmonton service area through its Lead Service Replacement Program. This program includes sending annual notifications to residents of homes with lead water service lines, offering complimentary tap-water testing for lead, offering a free point-of-use lead reduction filter and assisting the customer with the replacement of their lead water service line by prioritizing replacement of the line once the customer has decided to replace it. As a result of this program, the number of lead water service lines decreases each year as they are replaced. Presently, there are fewer than 3,400 lead water service lines in Edmonton (approximately 1.2% of the total water service lines in Edmonton), almost all of which have point-of-use lead reduction filters. The risk of contamination caused by lead water services lines in EPCOR's other service areas, including the U.S., is lower because the drinking water systems were constructed after 1950.

EWSI provides wastewater treatment services in Edmonton through operation of the Gold Bar wastewater treatment plant (Gold Bar). Gold Bar, which began operating in 1956 as a City owned facility, was transferred to EPCOR in 2009. Gold Bar is an advanced wastewater treatment plant with a focus on three areas of treatment: full treatment (biological nutrient removal and pathogen reduction) during normal weather conditions, enhanced primary treatment during wet weather conditions (heavy rain or snow melt) and membrane filtration for reclaiming water for re-use in industrial applications. Full treatment capacity of the plant is 310 million litres per day under normal weather conditions. During wet weather conditions, the plant processes increased wastewater flows from Edmonton's combined sanitary / storm sewer system. Under these conditions, the plant can remove floatable objects up to a capacity of 2,200 million litres per day and perform primary treatment processes up to 1,200 million litres per day, which includes up to 600 million litres per day that receives enhanced primary treatment for additional pollutant removal prior to discharge into the North Saskatchewan River. Using membrane filtration technology, up to 15 million litres per day of wastewater is reclaimed for industrial use.

EPCOR Water Arizona provides service through ten water utility districts, six wastewater utility districts, and various distribution and collection systems. EPCOR Water Arizona obtains water from three sources: (i) surface water mainly from the Central Arizona Project, a canal system built to bring water from the Colorado River to various areas in Arizona; (ii) groundwater wells; and (iii) treated effluent (mainly for commercial and / or irrigation use). Surface water is treated at three facilities, as shown in the table below:

Plant	**District**	**Production Capacity** [(1)] (millions of litres per day)
White Tanks	Agua Fria	62.09
Anthem	Anthem	26.50
Shea	Chaparral	62.79
Total		151.38

(1) Production capacity represents the amount of treated water that can be produced under maximum warm conditions with no plant shutdowns or detrimental raw water quality conditions. Actual production varies with seasonality, raw water conditions and customer demand.

EPCOR Water New Mexico provides water services to the city of Clovis, New Mexico and in the greater Edgewood area near Albuquerque, New Mexico through three water utility districts. Water in New Mexico is sourced entirely from groundwater wells.

EPCOR 130 sells and transports raw water to four municipalities in Travis County, Texas through an 85 kilometre, 30-inch pipeline that carries groundwater from a well field in Burleson County, Texas to a single termination point near the city of Manor, Texas. The design capacity of the pipeline is approximately 68 million litres per day of which only approximately 27 million litres per day is presently utilized under the four existing contracts. The EPCOR 130 Pipeline is operated and maintained under contract by one of the off-takers that purchases water from EPCOR 130. EPCOR regularly inspects the equipment and reviews the maintenance program to ensure the EPCOR 130 Pipeline is operated and maintained within regulatory requirements.

Non-owned Facilities Operated by EPCOR

In October 2012, EPCOR signed an agreement with Alberta Infrastructure to design, build, finance and operate the expansion and upgrade of the Evan-Thomas Water and Wastewater Facility in the Kananaskis Village area of Alberta. EPCOR commenced operation of the existing water and wastewater facility on December 2, 2012. Construction on the expansion and upgrade was substantially completed in August 2014. Since then, EPCOR has been operating the new facility and will continue to operate the system through 2024. In 2014, the Award of Merit was awarded for the Evan-Thomas Water & Wastewater Treatment Facility Upgrade Project by the Canadian Council for Public-Private Partnerships (CCPPP) to recognize outstanding achievement in the municipal sector.

In August 2014, EPCOR assumed operations of the existing wastewater treatment plant in the city of Regina and began construction of significant additions to the plant under a public-private partnership agreement. Substantial completion of the new construction was reached in December 2016, with final completion expected in the second quarter of 2017. This public-private partnership agreement includes transition of the City of Regina wastewater treatment plant staff to EPCOR, partially financing the newly constructed additions to the plant over a 30-year term and operation of plant also for a term of 30 years. The Regina Wastewater Project was awarded the C.W. Chuck Wills Award by the CCPPP in 2014 for innovation and excellence in public-private partnerships.

In February 2016, EPCOR signed an agreement to continue operating a selenium active water treatment facility at West Line Creek in Sparwood, British Columbia. The facility treats West Line Creek flow throughout the year and removes selenium and nitrates from the creek on a daily basis. EPCOR completed commissioning of the facility in late 2015 pursuant to an earlier agreement.

EPCOR also operates other water and wastewater facilities under contracts with various commercial, municipal and industrial customers in Alberta and British Columbia.

Competitive Conditions and Rate Regulation

EPCOR's subsidiaries have the exclusive right to provide water and wastewater services in Edmonton under franchise agreements with the City and in Arizona and New Mexico under certificates of convenience and necessity (CC&N). As a result, the majority of the Water Services business segment is rate regulated under either performance based or cost-of-service based frameworks by different regulators depending on the region. The Water Services business segment also earns income through competitive contract-based services.

Water Canada

EWSI has an exclusive franchise within the city of Edmonton for the provision of water to its population base. The franchise agreement for the provision of water services, between EWSI and the City, was extended for a 15-year term commencing January 1, 2004 with a right to renew for an agreed upon term. On March 31, 2009, the City and EWSI entered into another franchise agreement whereby EWSI was granted the exclusive right to provide wastewater treatment services within Edmonton. The wastewater franchise agreement will expire on May 31, 2029, but may be extended for an additional 10-year period and for as many such successive renewals as the City and EWSI may agree.

The City regulates the customer rates of EPCOR's water and wastewater operations within the city of Edmonton franchise under a performance based framework. Under the performance based framework, customer rates are adjusted for inflation and expected efficiency improvements over a five-year term. In October 2016, the City approved a new EPCOR Water Services and Wastewater Treatment Bylaw to cover the period from April 1, 2017 to March 31, 2021 (the 2017-2021 Performance Based Regulation (PBR) Bylaw). Through the 2017-2021 PBR Bylaw, EPCOR has the opportunity to recover its costs and earn a fair return on its investment. The 2017-2021 PBR Bylaw is designed to ensure customers receive stable and predictable rates over a five-year period while requiring EPCOR to meet performance measures in the areas of customer service, the environment, water quality, system reliability and employee safety.

Wholesale water services are provided by EPCOR to nine regional water service commissions surrounding Edmonton under long-term supply contracts. The Regional Water Customers Group (RWCG) represents seven of these regional customers. The water rates charged to the RWCG are calculated annually on a cost-of-service basis, which allows EPCOR to recover its actual costs and earn a fair return on its investment. These rates are subject to appeal to the AUC by way of a complaint application.

The Corporation's Water Services business segment also provides commercial water and wastewater operations and maintenance services to commercial, industrial and municipal customers in Alberta, British Columbia and Saskatchewan and earns margins on these contracts by satisfying the terms of the contracts while controlling operating costs. In its commercial water business, EPCOR faces competition from other water developers, including Canadian and international water companies. To grow the business, EPCOR must remain cost competitive and continue to demonstrate its technical water expertise and strong customer service focus.

Water U.S.A.

EPCOR Water Arizona, Chaparral and EPCOR Water New Mexico have water and wastewater operations provided under CC&N's approved by the regulatory body in each state. Each CC&N establishes the right and obligation to provide water or wastewater service for an indefinite period of time within a defined geographic area that may be expanded at the utility's request if approved by the state regulatory body governing that area.
In addition to regulating specific aspects of service, the Arizona Corporation Commission (ACC) regulates customer rates of EPCOR's Arizona water and wastewater customers under a cost-of-service based framework that allows utilities to recover operating costs and earn a fair return on invested capital. Both EPCOR Water Arizona and Chaparral are required to apply to the ACC for changes in the rates charged for service. A rate increase request is primarily based on the sufficiency of revenues to cover, operating expenses and capital costs at the end of the test year, which is the year that immediately precedes the rate application.

EPCOR Water New Mexico is subject to the rules and rate regulations of the New Mexico Public Regulation Commission under a similar framework to EPCOR Water Arizona and Chaparral.

Water rates for EPCOR 130 are set pursuant to long-term wholesale water supply contracts which are subject to appeal to the Texas Public Utilities Commission.

Environmental Regulation and Initiatives

EPCOR is subject to federal, provincial, state and municipal environmental laws, regulations and guidelines concerning its businesses. EPCOR is committed to complying with or surpassing environmental regulatory requirements and minimizing the environmental impact of its operations. EPCOR is also committed to working with stakeholders with a view of protecting the environment and, at the same time, encouraging and sustaining economic development. EPCOR incorporates environmental management practices in its strategy, policies, processes and procedures. To achieve this, EPCOR has implemented an environmental management system (EMS) based on the International Organization for Standardization (ISO) environmental management standard, ISO 14001, in its facilities. These systems encompass identification of the scope, objectives, training and stewardship of EPCOR's environmental responsibility. Each facility is also subject to environmental audits to help ensure compliance with its EMS and all applicable compliance obligations. As at December 31, 2016, operations at the Gold Bar, Evan-Thomas Water and Wastewater Treatment Facility, and Edmonton water treatment plants and reservoirs were ISO 14001 registered.

In Alberta, drinking water quality and wastewater effluent quality for EPCOR's water and wastewater treatment operations, respectively, are regulated under the provincial *Environmental Protection and Enhancement Act* (EPEA). Regulation under the EPEA takes the form of an "Approval-to-Operate" which, specifies, among other things, requirements for the quality of treated water, the number, frequency and type of water quality testing, as well as mandatory standards for the water and wastewater treatment processes. The drinking water quality requirements in Alberta meet or exceed the national Guidelines for Canadian Drinking Water Quality recommended by Health Canada. EPCOR ensured these prescribed requirements were met in 2016 by collecting data from more than 130,000 tests during the year on approximately 190 physical, chemical and microbiological parameters in its accredited laboratory. More than 4,100 additional tests for approximately 206 parameters were sent to external accredited laboratories for analysis. Plant operations staff performed more than 25,000 additional lab tests for process control and used approximately 210 continuous online water quality analyzers. Similar testing for water, wastewater and industrial operations is also performed at other EPCOR operating sites in Alberta, British Columbia and Saskatchewan.

The Edmonton waterworks system, including the E.L. Smith and Rossdale water treatment plants, and the reservoirs and water distribution system, has an innovative Approval, issued in 2011, by the Alberta Environment and Parks department of the Alberta government under the EnviroVista "Champion" program. EnviroVista is a voluntary program, for Alberta industrial, manufacturing and municipal water operations, that applies to facilities which have approvals under the EPEA. As part of the EnviroVista commitments, EPCOR has constructed and commissioned facilities to dechlorinate all chlorinated water discharges from its Edmonton water treatment plants and operate in direct filtration mode for up to seven months per year in order to reduce solids returned to the North Saskatchewan River.

EPCOR is an active member of the North Saskatchewan Watershed Alliance, the watershed planning and advisory council for the North Saskatchewan River basin, and is actively involved with the Alberta Water Council to promote watershed management programs. These programs serve to better manage watersheds and protect the North Saskatchewan River from impurities such as soil particles, excess nutrients, fertilizers, microbiological contaminants and organic pollutants. Watershed protection planning and implementation activities are also underway for other areas of Alberta.

In 2016, $21 million was spent on facility and treatment process improvements targeted at environmental compliance and performance improvement in Canada. This included upgrades to Gold Bar grit tank numbers 4 and 5 to improve the capture and removal of grit from wastewater. The improvements also included progress on the construction of a hydrovac sanitary grit treatment facility to remove and clean grit from vacuum truck slurry and eliminate the need to transport and dispose of sanitary grit at the Clover Bar lagoons. Additional improvements at Gold Bar that will continue in 2017 include the rehabilitation and upgrade of digester number 3, odour control system improvements, and biogas risk mitigation, upgrades and utilization.

EPCOR was the successful proponent in a bid to upgrade and operate the wastewater treatment plant in Regina, Saskatchewan. The existing facility required wastewater treatment process upgrades including biological nutrient removal (BNR). The upgraded BNR plant will be fully operational in 2017 and will substantially reduce the loading of nutrients, such as nitrogen and phosphorous, into Wascana Creek and the Qu'appelle River. EPCOR expects that the reduction in nutrient loading from wastewater effluent will provide a significant environmental benefit by improving the aquatic health of Wascana Creek and the Qu'appelle River.

Drinking water quality and wastewater standards for EPCOR's U.S. operations are regulated by the U.S. Environmental Protection Agency (U.S. EPA) under the *Safe Drinking Water Act* and *Clean Water Act*, respectively. Among other things, the U.S. Environmental Protection Agency sets drinking water standards specifying the treatment, source water protection, operator training and funding for water system improvement and relies on the states and localities to carry out the standards. Oversight of water and wastewater systems is conducted by state and county authorities to the degree that they establish standards at least as stringent as the U.S. EPA. This oversight takes the form of annual operating permits, approval of construction permits and / or approval to discharge permits. Wastewater discharge that may adversely impact aquifers or ground water is exclusively regulated at state levels. The associated aquifer water quality rules vary by state, but generally take the form of aquifer protection-type permits. In 2016, EPCOR's U.S operations worked to meet drinking water standards by conducting over 20,000 water quality tests on over 100 regulated physical, chemical and microbiological parameters.

Although there are no formal watershed protection groups in the Arizona and New Mexico service areas, all water systems in these states underwent source-water assessments to determine whether, and to what degree, the sources were vulnerable to contamination from adjacent land uses. EPCOR Water Arizona's and EPCOR Water New Mexico's wells are protected from contamination by proper well construction, system operation and management. EPCOR Water Arizona acts as the lead agent in the West Valley Central Arizona Project Subcontractors, a regional partnership focused on full utilization and augmentation of surface water supplies in the western portion of the greater Phoenix area.

Revenues and Sales Volumes

The Water Services business segment, including EWUS and its subsidiaries, represented approximately 31% of EPCOR's total revenues in 2016 and 32% in 2015. EWUS represented approximately 32% of the Water Services business segment revenues in 2016 and 28% in 2015.

EPCOR's core water market is stable as it has the exclusive franchise to provide water and wastewater treatment within Edmonton. Twenty-year water supply agreements have been signed with the seven RWCG members which in turn supply water to over 65 surrounding communities and counties. Six of these agreements expire in 2018 and one is set to expire in 2023.

The following tables show a three year history of EPCOR's annual Canadian water sales volumes for Edmonton and surrounding regions and U.S. water sales volumes for EPCOR Water Arizona, EPCOR Water New Mexico, Chaparral for the past three years and EPCOR 130 for a partial year in 2016:

Greater Edmonton Water Sales Volumes

(millions of litres)	2016	2015	2014
Residential	45,421	46,920	44,876
Multi-Residential	17,987	18,071	17,696
Commercial and Industrial	28,131	29,016	28.572
Wholesale (to RWCG)	34,825	35,986	35,416
Total	126,364	129,993	126,560

U.S. Water Sales Volumes

(millions of litres)	2016	2015	2014
Residential	62,610	58,571	59,366
Multi-Residential	-	-	-
Commercial and Industrial	22,634	20,957	22,456
Wholesale (by EPCOR 130)	650	-	-
Total	85,894	79,528	81,822

Seasonality

EPCOR's Water Services business as a whole, experiences seasonal consumption-based sales volume variability, with higher water sales occurring in summer months, particularly when precipitation levels are low and temperatures are high. These higher sales volumes also cause higher consumption based expenditures.

Water Canada's water treatment costs can vary due to seasonality and in particular during spring run-off, depending on raw water quality.

DISTRIBUTION AND TRANSMISSION

EPCOR's Distribution and Transmission business segment owns and operates high voltage substations, transmission lines and cables that are situated within and around Edmonton and form part of the Alberta Interconnected Electric System (AIES) power grid. Through these facilities, EDTI provides transmission services to the Alberta Electric System Operator (AESO), an independent not-for-profit entity which operates the AIES. EDTI also owns and operates aerial and underground distribution lines and related facilities for the distribution of power to customers within its distribution service area in Edmonton.

EPCOR Technologies Inc. (Technologies), a wholly-owned non-material subsidiary of the Corporation accounted for as part of the Distribution and Transmission business segment, provides design, construction and maintenance services to the City. Technologies works primarily with transportation electrical infrastructure, such as street lighting, traffic signals, light rail transit and cathodic protection services, primarily within the city of Edmonton.

Facilities

EDTI transmits electrical energy with 72 kV, 138 kV, 240 kV and 500 kV lines and cables routed through 30 substations that are situated within Edmonton. The substations feed distribution delivery points within Edmonton. EDTI operates approximately 257 circuit kilometres of aerial and underground transmission lines and cables, which are interconnected with the AIES and are largely situated on lands held under easements, utility rights-of-way and licenses or permits for rights-of-way.

EDTI distributes electrical energy to customers in Edmonton through five distribution substations, 288 distribution feeders and 5,543 circuit kilometres of primary distribution lines at 15 kV and 25 kV. In 2016, EPCOR distributed approximately 13.31% of provincial energy consumption to 352,853 residential and 36,935 commercial consumers in Edmonton.

Competitive Conditions and Rate Regulation

EDTI has the exclusive right to provide electricity distribution services in Edmonton under a 20-year franchise agreement between EDTI and the City. The franchise agreement expires on January 1, 2024 and may be extended for any term agreed upon between EDTI and the City. EDTI provides electricity transmission services within its service area pursuant to Section 9 of the AESO Rules. As a result, all of the Corporation's Distribution and Transmission business segment is provincially rate regulated by the AUC.

EDTI's distribution function is regulated under the AUC's performance based framework. Under the framework, rates are set based on an inflation factor less a productivity factor plus, a growth factor and an incremental capital additions factor. In addition, EDTI can apply for additional funds to fund capital expenditures based on "capital tracker" rules. The current performance based framework will be used to set rates to December 31, 2017. In December 2016, the AUC issued its 2018-2022 Performance Based Regulation Decision, which sets out how the PBR framework will be modified for the 2018 – 2022 time frame.

EPCOR's transmission function is regulated pursuant to the *Electric Utilities Act* (EU Act) under a cost-of-service framework that allows utilities to recover forecast operating costs, including depreciation and amortization, and to earn a fair return on invested capital.

In October 2016, the AUC issued its 2016 Generic Cost of Capital decision for all Alberta natural gas and electricity distribution and transmission utilities setting the generic return on equity at 8.30% retroactively to January 1, 2016 for 2016 and 8.50% for 2017. The generic rate of return was previously 8.30%. The AUC also adjusted the debt / equity ratio to 63% / 37%. Previously the debt / equity ratio applicable to EPCOR's distribution function was 60% / 40% and applicable to EPCOR's transmission function was 64% / 36%.

In November 2013, the AUC issued a decision in the Utility Asset Disposition Review proceeding directing that certain gains or losses due to extraordinary retirement of assets, be borne by shareholders and not to be reflected in customer rates. In September 2015, the Alberta Court of Appeal upheld the AUC's decision.

The *Code of Conduct Regulation* under the EU Act regulates the sharing of information and services between regulated and non-regulated affiliated electric utility entities and results in reporting and compliance obligations for the Corporation's regulated entities. EPCOR is also subject to an Inter-Affiliate Code of Conduct separately approved by the AUC for EPCOR in February 2004 (the EPCOR Code), as amended. The EPCOR Code defines a framework for the management, staffing, information disclosure and commercial relationships among the EPCOR subsidiaries providing utility services. The reporting and audit obligations arising from the EPCOR Code reside with the affected EPCOR utility subsidiaries.

The Technologies division of the Corporation's Distribution and Transmission business segment competes with other companies that provide similar electrical transportation infrastructure support services.

Environmental Regulation and Initiatives

The Distribution and Transmission business segment assets include aerial and underground distribution and transmission facilities, substations, switchyards, service centres and a de-watering site. As at December 31, 2016, the operations at all of related facilities, including Technologies' street lighting, traffic signal and light rail transit and cathodic protection operations, were ISO 14001 registered. The substations and switchyards do not require environmental approvals to operate but they are subject to regulations governing spills, noise and the release of sulfur hexafluoride contained in gas-insulated switchgear equipment. These requirements and the associated risks are well known and are appropriately managed. Other environmental activities include the management and proper disposal of polychlorinated biphenyls (PCB) remaining in the electrical system and wooden poles impregnated with pentachlorophenol or copper chromate. These activities are governed by federal, provincial and municipal levels of government, often concurrently, through regulations and bylaws.

EDTI has twelve 72 kV and two 240 kV Oil Filled Pipe Type (OFPT) underground transmission cables which cross underneath the North Saskatchewan River at various locations throughout the Edmonton river valley. The OFPT cables contain PCB-free oil which provides electrical insulation and a means for transmitting heat generated by the cable conductors to the exterior of the pipe. A breach of the OFPT cable underneath or on the bank of the North Saskatchewan River could result in the release of cable oil into the river. To reduce potential environmental damage associated with an oil release, EDTI has installed barrier splices in the OFPT cables at river crossings and continuous monitoring devices and alarms in its control center.

Capital expenditures related to distribution and transmission environmental initiatives were approximately $1 million in 2016 primarily for PCB transformer replacements. EDTI is currently in compliance with Environment Canada PCB regulations and is on track to meet the deadline to remove all PCBs by 2025.

All Distribution and Transmission environmental activities are supported and managed through its ISO 14001 certified EMS.

Revenues and Sales Volumes

The Distribution and Transmission business segment represented approximately 30% of EPCOR's total revenues in 2016 and 28% in 2015.

Revenues from EDTI consist of a regulator-approved revenue requirement to cover operation, maintenance and administrative costs plus a fair return on invested capital. This business segment also includes unregulated commercial service revenues related to Technologies' transportation electrical infrastructure services.

The following table outlines electricity distribution volumes, net of line losses (electricity lost as it is transmitted across distances):

Power Distribution Volumes

(000's of megawatt hours)	**2016**	**2015**	**2014**
Residential	2,118	2,080	2,073
Commercial	5,491	5,589	5,684
Total	7,609	7,669	7,757

Seasonality

EDTI's normal business experiences some seasonality with respect to construction and associated expenditures. As work scheduling permits, EDTI shifts projects requiring significant excavation work to the summer / autumn timeframes to avoid incurring higher costs associated with performing such work in the winter.

ENERGY SERVICES

EPCOR's Energy Services business segment operates through EEA LP and provides RRO electricity service to residential, farm and small commercial consumers within Edmonton, several Rural Electrification Association service territories and the FortisAlberta Inc. service territory. Energy Services also provides default supply electricity services to customers that consume more than 250-megawatt hours of electricity (the amount of electricity generated by one megawatt operating for one hour) per year in these service areas. The Energy Services business segment also sells electricity and natural gas to Alberta consumers under contracts through its Encor brand. In addition, Energy Services provides billing, collection and contact centre services to its RRO and Encor customers, the City's Waste and Drainage departments and to EWSI.

EPCOR's Energy Services business is subject to the *Code of Conduct Regulation* under the EU Act and Inter-Affiliate Code of Conduct as described above.

Competitive Conditions and Rate Regulation

The Corporation has the exclusive right to provide RRO electricity services to customers in the EDTI electricity distribution service area. The Corporation also has the exclusive right to provide RRO electricity services to customers in FortisAlberta Inc.'s electricity distribution service area under a contract through the year 2020 with a five-year to extension option. Prior to that, the Corporation plans to negotiate a new contract with Fortis Alberta Inc. As a result, the RRO business, which comprises the majority of the Corporation's Energy Services business segment, has its rates regulated by the AUC under a cost-of-service based framework. The cost-of-service based framework allows the Corporation to recover forecast operating costs, including depreciation and amortization, and earn a fair margin.

All retail electricity customers in Alberta have a choice of retailers from whom they may purchase electricity. The RRO is the default option for these customers if they have not entered into contracts with a competitive electricity retailer. The RRO is a regulated electricity pricing option available to all eligible residential, commercial and farm / irrigation customers who consume less than 250-megawatt hours of electricity per year. Approximately 39% of total electricity consumption in Alberta, excluding self-retailers, is RRO eligible. Approximately 55% of residential and 43% of small commercial RRO eligible customers have chosen to stay with the RRO (i.e. they have not signed a contract with a competitive electricity retailer)[1]. Municipal, industrial and large commercial customers are not eligible for the RRO.

The *RRO Regulation* of the EU Act (RRO Regulation) has been extended to April 30, 2020. The RRO Regulation requires all RRO providers to provide a hedged rate to eligible customers. A hedged rate means EPCOR enters into financial transactions, under an AUC regulated energy price setting plan (EPSP), to lock in fixed prices for each month, which are used to set the RRO rate in advance of customers consuming the energy.

Under its current approved EPSP, EEA LP bears price and volume risks and is compensated through the margins in customer rates for incurring such risks. In March 2015, the AUC increased the return margin allowed to be earned for the provision of RRO electricity services and reduced the risk margin allowed to be earned for bearing the commodity risk in providing RRO electricity services. The increased return margin part of this decision was implemented on an expedited basis and came into effect in August 2015. The remainder of the current EPSP, including the decreased commodity risk margins, came into effect in August 2016.

In the deregulated electricity marketplace, increased competition combined with new service offerings and different pricing strategies from competitors may result in loss of EPCOR RRO customers. Competition has, and is expected to continue to come from Alberta's non-regulated retailers.

In November 2016, the Alberta government announced a 6.8 cent per kilowatt hour cap on RRO rates. The cap will be implemented by June 2017 and run until 2021. While the rate cap is in effect, RRO customers will pay the lower of the cap or the market based RRO rate. The government has assured RRO providers that they will be kept whole for rates that exceed the RRO cap. Also in November, the Alberta government announced a ban on door-to-door energy sales. The cap on RRO rates and the ban on door-to-door energy sales have the potential to reduce RRO customer attrition and may result in growth of EPCOR RRO customers.

In May 2014, the Corporation entered the competitive retail market by offering electricity and natural gas contracts to Alberta consumers under the Encor brand in order to mitigate the impact of RRO customer attrition. The expanded service offering, including green energy options, provides customers wishing to move from the RRO to a competitive contract with an EPCOR offering. The 6.8 cent per kilowatt hour price cap announced by the Alberta government has the potential to slow down Encor's electricity contract customer growth or lead to Encor customer attrition with customers moving to the EPCOR or other electricity retailer RRO.

Revenues and Sales Volumes

The Energy Services business segment represented approximately 39% of EPCOR's total revenues in 2016 and 40% in 2015.

The following table outlines EPCOR's retail power sales volumes for the periods indicated:

Retail Power Sales

(gigawatt hours)	**2016**	**2015**	**2014**
RRO	4,919	4,947	5,085
Default & Competitive Supply	772	761	704
Total Power Sales	5,691	5,708	5,789

Seasonality

EEA LP experiences seasonal consumption-based sales volume variability, with higher consumption months being those with fewer daylight hours and those with hotter weather, leading to high air conditioning electricity load.

These higher sales volumes also cause higher consumption based expenditures.

[1] As of March 2016, based on MSA Retail Statistics (2016-08-08 version) http://albertamsa.ca/uploads/pdf/Retail%20Statistics/2016-08-08-Retail-statistics.xlsx

CORPORATE

The Corporate business segment includes Corporate Services and EPCOR's financial interest in Capital Power.

Corporate Services

EPCOR's Corporate Services provides certain centralized support services to the Corporation's other business segments. Corporate services provided are based on specialized knowledge, experience, technology and cost effectiveness of providing services centrally. These services include governance, finance, treasury, internal audit, information services, supply chain management, human resources, public and government affairs, legal, and health, safety and environment services.

Capital Power

As a result of the sale of EPCOR's power generation business in 2009, EPCOR owned exchangeable partnership units of Capital Power L.P. which were exchangeable for voting common shares of Capital Power Corporation. EPCOR also holds loans receivable in the form of a back-to-back debt obligation from Capital Power that generally matches the payment provisions of certain EPCOR debt obligations.

Since 2009, through a number of secondary market prospectus distributions, EPCOR reduced its interest in Capital Power, including in April 2015 when EPCOR exchanged 9,450,000 limited partnership units for an equal number of common shares of Capital Power which were immediately sold at an offering price of $23.85 per share for aggregate gross proceeds of $225 million. At the same time, EPCOR exchanged all of its remaining 9,391,000 exchangeable limited partnership units for common shares of Capital Power. Following the completion of the exchange, EPCOR no longer exerted significant influence over Capital Power. Accordingly, the Corporation accounted for its investment in Capital Power up to December 31, 2016 as available for sale. In 2016, the Corporation sold 9,141,636 of the 9,391,000 remaining shares in Capital Power for aggregate gross proceeds of $204 million and sold the remaining 249,364 shares on January 3, 2017. The Corporation plans to reinvest the proceeds in EPCOR's infrastructure and Energy Services businesses.

A Back-to-Back Credit Agreement governs the loans receivable from Capital Power (see Material Contracts section). This agreement was amended and restated in 2016, primarily to transfer the obligations of Capital Power L.P. to Capital Power Corporation. Approximately $712 million of the loans were contractually retired on or before December 31, 2016, with the remainder maturing on or before June 30, 2018. As part of the Amended and Restated Back-to-Back Credit Agreement, EPCOR has the right to call the remaining debt owed by Capital Power in certain situations.

The following table outlines EPCOR's financial interest in Capital Power:

	As at December 31		
($ in millions)	**2016**	**2015**	**2014**
Economic interest in Capital Power	0.3%	9.6%	18.4%
Investment in Capital Power	$6	$167	$386
Loans receivable from Capital Power	$184	$323	$332

PERSONNEL

As at December 31, 2016, EPCOR employed 2,771 full-time, part-time, temporary and casual employees.

	As at December 31		
	2016	**2015**	**2014**
Water	1,150	1,174	1,140
Distribution and Transmission	1,077	1,097	1,067
Energy Services	275	256	233
Corporate	269	268	270
Total	2,771	2,795	2,710

EPCOR has a strong working relationship with its five labour unions; four based in Alberta and one in Saskatchewan. As of December 31, 2016, the five labour unions represented 1,772 employees.

EPCOR has not experienced any labour disruptions since 1978.

SPECIALIZED SKILLS AND KNOWLEDGE

Technical, professional and trades skills are key to the Corporation's ability to continue delivering services to customers in a safe and reliable manner. Water Services hires and trains experienced and certified water plant, water distribution system, wastewater treatment, wastewater collection system and laboratory operators and technicians. Distribution and Transmission hires and trains system control operators, signal technicians, and powerline and power system electricians. Furthermore, the Corporation also hires and trains engineers and other technical and financial professionals across the entire business. The Corporation also develops various trades people through its apprenticeship programs and ongoing skills certification and technical training.

RISK FACTORS

A discussion of the risk factors relating to EPCOR and its business and operations can be found in the section entitled "Risk Factors and Risk Management" in the Corporation's MD&A dated March 2, 2017 for the year ended December 31, 2016.

DIVIDEND POLICY

Annual dividends declared and paid during 2014 to 2016 were $141 million per year. Under EPCOR's dividend policy, the annual dividend commencing in 2017 is set at $146 million per year, until a further change is recommended by the Board of Directors (the Board) and approved by EPCOR's Shareholder. Dividends for each year will be reviewed annually by the Board and the Shareholder and are subject to amendment in the event of significant change in EPCOR's business or financial condition.

Certain debentures of the Corporation contain restrictions on the payment of non-cumulative dividends, including dividends on the Corporation's common shares if the consolidated funded obligations exceed 75% of total consolidated capitalization.

CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of common shares. As of December 31, 2016, there were three common shares of the Corporation issued and outstanding, all of which are owned by the City. Under its Articles of Incorporation, the Corporation cannot issue equity securities, including common shares, other than to the City, unless the City approves such issuance. None of the common shares issued by the Corporation are quoted or traded on a public exchange. As of December 31, 2016, common shares are the only class of equity security that the Corporation is authorized to issue.

CREDIT RATINGS

The following information relating to EPCOR's credit ratings is provided as it relates to EPCOR's financing costs and liquidity. Specifically, credit ratings affect EPCOR's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current ratings on the Corporation's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the ratings outlook, could adversely affect the Corporation's cost of new or renewal financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Corporation's ability to, and the associated costs of, enter into normal course derivative or hedging transactions or its ability to maintain ordinary course contracts with customers and suppliers on acceptable terms.

Credit ratings are intended to provide investors with an independent assessment of the credit quality of an issue or an issuer of securities and such ratings do not address the suitability of a particular security for a particular investor. The ratings assigned to a security may not reflect the potential impact of all risks on the value of the security. A credit rating is not a recommendation to buy, sell or hold securities and may be subject to revision and withdrawal at any time by the credit rating organization. The Corporation pays the applicable rating agency fees to have its debt rated by the rating agency.

Standard and Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc. (S&P)

A-: Senior Unsecured Debt and Issuer Rating – The A- rating assigned to the Corporation's Senior Unsecured Debt is within the A rating category, which is the third highest rating of S&P's ten rating categories, which range from AAA to D. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. S&P's ratings outlook of EPCOR is stable, which reflects their expectation that the rating is not likely to be changed over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and / or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future S&P credit action.

S&P Rating Description: An obligor rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

DBRS Limited (DBRS)

A (low): Senior Unsecured Debentures and Issuer Rating – The A (low) rating assigned to the Corporation's Senior Unsecured Debentures and Issuer Rating is within the A rating category which is the third highest rating of DBRS' ten rating categories, which range from AAA to D. DBRS also uses "high" and "low" subcategories on ratings from AA to C to indicate the relative standing of the securities being rated within a particular rating category. DBRS' trend outlook for EPCOR is stable, reflecting DBRS' expectation of no changes in rating if present circumstances continue. DBRS assigns rating trends based primarily on an evaluation of the issuing entity, but may also include consideration of the outlook for the industry in which the issuing entity operates giving consideration to developments that could positively or negatively impact the sector or the issuer's debt position within the sector.

DBRS Rating Description: Good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than AA. May be vulnerable to future events, but qualifying negative factors are considered manageable.

R-1 (low): Commercial Paper – The R-1 (low) rating assigned to the Corporation's short-term debt is within the R-1 rating category which is the highest rating of DBRS' six rating categories for short-term debt obligations, which range from R-1 to D. DBRS also uses "high", "middle" and "low" subcategories on short-term ratings from R-1 to R-5 to indicate the relative standing of the securities being rated within a particular rating category. The outlook trend for this rating is stable reflecting DBRS's expectation of no likely changes if present circumstances continue.

DBRS Rating Description: Good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial. Overall strength is not as favorable as higher rating categories. May be vulnerable to future events, but qualifying negative factors are considered manageable.

Credit Ratings Related Fees

The Corporation pays rating agency fees to have its debt rated by S&P and DBRS. In the past two years, EPCOR paid S&P and DBRS fees for annual ratings maintenance. In addition, DBRS was compensated for the renewal of EPCOR's Base Shelf Prospectus and for providing indicative stand-alone ratings on select EPCOR subsidiaries.

TRANSFER AGENT AND REGISTRAR

BNY Trust Company of Canada, at its office located at Toronto, Ontario, is the trustee (Trustee) under the Corporation's indenture. Registers for the registration and transfer of the Senior Unsecured Debentures are kept at the offices of the Trustee in Toronto, Ontario. The Trustee is also the paying agent for the Senior Unsecured Debentures.

MATERIAL CONTRACTS

Apart from contracts entered into in the ordinary course of business, EPCOR has entered into one material contract, being an Amended and Restated Back-to-Back Credit Agreement dated January 28, 2016 between EPCOR, as lender and Capital Power, as borrower, that governs the back-to-back debt obligation in the aggregate amount of approximately $896 million. The material contract can be found on SEDAR at www.sedar.com.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no directors or executive officers or other insiders of the Corporation, or any associates or affiliates of the foregoing, who had material interests in any transaction or proposed transaction involving the Corporation in the financial year ended December 31, 2016, which has materially affected or would materially affect the Corporation.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, none of the directors or executive officers of the Corporation, and no associate of any of them, is or was in the most recently completed financial year indebted to the Corporation, except for routine indebtedness.

INTERESTS OF EXPERTS

KPMG LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

OFFICERS OF THE CORPORATION

Following are the names, province / state and country of residence of EPCOR's executive officers as at December 31, 2016, and their positions and offices within EPCOR and principal occupations during the preceding five years:

Name, Province/State, Country of Residence and Office	Principal Occupation During Past Five Years
Guy Bridgeman Alberta, Canada Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer from May 2013; prior thereto, Senior Vice President, Finance, Planning and Development from February 2013; prior thereto, Senior Vice President, Strategic Planning and Development from July 2009.
Hanan Campbell Alberta, Canada Associate General Counsel	Associate General Counsel from March 2014; prior thereto, Senior Legal Counsel from July 2009.
John Elford Alberta, Canada Senior Vice President, Water Canada	Senior Vice President, Water Canada from January 2015; prior thereto, Divisional Vice President, EPCOR Distribution and Transmission from February 2013; prior thereto, Director, Regulatory Affairs, EPCOR Distribution and Transmission from March 2011; prior thereto, Director Planning and Project Management, EPCOR Distribution and Transmission from December 2009.
Joseph Gysel Arizona, United States Senior Vice President, EPCOR Water USA (President, EWUS)	Senior Vice President, EPCOR Water USA (President, EWUS) from December 2011; prior thereto, Senior Vice President, New Business Enterprises from September 2011; prior thereto, Senior Vice President, Water Development, EPCOR Water Services Inc. from July 2009.
Stuart Lee Alberta, Canada President and Chief Executive Officer	President and Chief Executive Officer from September 2015; prior thereto Senior Vice President, Corporate Development and Commercial Services, Capital Power Corporation from April 2015 to August 2015; prior thereto Senior Vice President Finance and Chief Financial Officer, Capital Power Corporation from July 2009 to March 2015 and President, CPI Income Services Ltd. from July 2009 to November 2011.
Francesco (Frank) Mannarino Alberta, Canada Senior Vice President, Electricity Operations	Senior Vice President, Electricity Operations from May 2013; prior thereto, Divisional Vice President, EPCOR Water Canada from September 2010; prior thereto, Production Manager, Shell Canada from November 2006.
Jamie Pytel (1) Alberta, Canada General Counsel and Corporate Secretary	General Counsel and Corporate Secretary from March 2014; prior thereto, Associate General Counsel, Corporate Secretary and Ethics Officer from August 2012; prior thereto, Acting Associate General Counsel, Acting Corporate Secretary and Ethics Officer from March 2012; prior thereto, Acting Associate General Counsel, Acting Assistant Corporate Secretary and Ethics Officer from March 2011; prior thereto, Senior Legal Counsel, Litigation and Ethics Officer from July 2009.

Susan (Amanda) Rosychuk Alberta, Canada Senior Vice President, Corporate Services	Senior Vice President, Corporate Services from March 2014; prior thereto, Senior Vice President, Human Resources and Information Services from May 2013; prior thereto, Divisional Vice President, Municipal Water and Wastewater Operations from September 2010; prior thereto, Senior Vice President, Field Services from July 2009; prior thereto, Divisional Vice President, EPCOR Distribution & Transmission Inc. from March 2009.
Duane Sommerfeld Alberta, Canada Treasurer	Treasurer from January 2015; prior thereto, Treasurer and Divisional Vice President, Technologies from January 2014 to December 2014; prior thereto, Treasurer and Corporate Controller from November 2013; prior thereto, Corporate Controller from July 2009.
Stephen Stanley Alberta, Canada Senior Vice President, Commercial Services	Senior Vice President, Commercial Services from January 2015; prior thereto, Senior Vice President Water Canada and Technologies from January 2014 to December 2014; prior thereto, Senior Vice President, Water Services Canada from December 2011; prior thereto, Senior Vice President, Water Services from November 2004.
Pamela Zrobek Alberta, Canada Corporate Controller	Corporate Controller from January 2014; prior thereto, Controller, EPCOR Distribution & Transmission Inc. from June 2006.

(1) Resigned January 31, 2017.

While EPCOR considers gender diversity when appointing executive officers, it does not currently have a written policy regarding this and does not currently set targets regarding representation of women in executive officer positions. At December 31, 2016, 36% of the Corporation's executive officers were women.

CORPORATE GOVERNANCE

Board Mandate

The Board operates under the Charter of Expectations for the Board, attached to this AIF as Appendix II.

Position Descriptions

The Board, except as limited by the Unanimous Shareholder Agreement, has the power to manage the business and affairs of the Corporation, and, by proxy through the Chief Executive Officer, sets out clear expectations for management. The Board has adopted Chair of the Board Terms of Reference as well as Terms of Reference for an Individual Director and each of the Board committees. Each Board committee's Terms of Reference specifies the duties and responsibilities delineated to the committee by the Board.

The Board has developed a written position description for the Chief Executive Officer and annually determines the Chief Executive Officer's objectives and conducts an evaluation of the Chief Executive Officer's performance against the established objectives.

Directors of the Corporation

Following are the names, province / state and country of residence of the directors as of the date of this AIF, their date of birth, year appointed, expiry of term, principal occupations during the preceding five years and their relevant skills and experience:

Hugh J. Bolton, FCA Alberta, Canada Date of Birth: May 1938 Year appointed: 2000 Term expires: 2018	**Principal Occupation During Past Five Years:** Corporate Director.

Skills and Experience:
Mr. Bolton is a Chartered Accountant and Fellow of the Chartered Professional Accountants of Alberta. He holds a Bachelor of Arts degree in Economics and an Honorary Doctor of Laws degree, both from the University of Alberta. He is former Chairman, Chief Executive Officer and partner of Coopers & Lybrand and presently serves as a director of WestJet Airlines Ltd. and is a former board member Capital Power Corporation, Teck Resources Limited, TD Bank Financial Group, Canadian National Railway and Matrikon Inc. In 2006, Mr. Bolton received a fellowship from the Institute of Corporate Directors (Canada). In 2010 he received a Lifetime of Achievement Award from the Alberta Institute of Chartered Accountants and in 2015 received an Honorary Doctor of Laws from the University of Alberta.

Vito Culmone Alberta, Canada Date of Birth: November 1964 Year appointed: 2013 Term expires: 2017	**Principal Occupation During Past Five Years:** Executive Vice President and Chief Financial Officer, Shaw Communications Inc. from June 2015; prior thereto Executive Vice-President, Finance and Chief Financial Officer, WestJet Airlines Ltd March 2007 to June 2015.

Skills and Experience:
Mr. Culmone obtained his Chartered Accountant designation in 1989 and holds a Bachelor of Commerce degree from the University of Toronto. He serves as the Executive Vice President, Finance and Chief Financial Officer of Shaw Communications Inc. In this position he is responsible for the overall financial management of Shaw Communications Inc. and its financial reporting. Prior to joining Shaw Communications Inc. in June 2015, Mr. Culmone served as Executive Vice President, Finance and Chief Financial Officer of WestJet Airlines Ltd. from March 2007 to May 2015 and had oversight of multiple corporate functions. Prior to joining WestJet Airlines Ltd., Mr. Culmone had a 12-year career at Molson Inc. where his previous roles included Vice President, Controller and Corporate Finance, Molson Inc. (pre-merger with Coors); Vice President and Chief Financial Officer of Molson U.S.A; and Vice President, Commercial Finance at Molson Canada.

Robert G. Foster California, United States Date of Birth: January 1947 Year appointed: 2014 Term expires: 2018	**Principal Occupation During Past Five Years:** Consultant, Prometheus Advisors, and Corporate Director; prior thereto Mayor of Long Beach, California from July 2006 to July 2014.

Skills and Experience:
Mr. Foster holds a Bachelor of Administration degree in Public Administration from San Jose State University. He currently serves as a director for sPower and Total Transportation Services, Inc. and on the Advisory Board of Gridco Systems. He recently served as Chairman of the California Independent System Operator and as Mayor of the City of Long Beach, California. He has also served as President of Southern California Edison.

Allister J. McPherson Alberta, Canada Date of Birth: September 1943 Year appointed: 2008 Term expires: 2018	**Principal Occupation During Past Five Years:** Corporate Director.

Skills and Experience:
Mr. McPherson holds a Masters of Science degree from the University of British Columbia. He served as Executive Vice President of the Canadian Western Bank and was Deputy Provincial Treasurer, Finance and Revenue, for the Province of Alberta. Mr. McPherson is presently an external member of the University of Alberta’s Investment Committee. He is past Chair of the Credit Union Deposit Guarantee Corporation, a past Director of The Churchill Corporation and Capital Power Corporation and has served on the Endowment Fund Policy Committee of Alberta Finance and the Edmonton Regional Airports Authority Board of Directors.

Douglas H. Mitchell, C.M., Q.C. Alberta, Canada Date of Birth: February 1939 Year appointed: 2001 Term expires: 2017	**Principal Occupation During Past Five Years:** National Co-Chair, Borden Ladner Gervais LLP (law firm) from January 2007 to November 2013.

Skills and Experience:
Mr. Mitchell holds a Bachelor of Laws degree from the University of British Columbia and a Bachelor of Arts degree from Colorado College. He presently is or has served as National Co-Chair of Borden Ladner Gervais LLP, Chair of the Calgary Airport Authority, Chair of the Calgary Sports Tourism Authority, Legacy Sports Inc., Co-Chair of the Banff Global Business Forum, Vice-Chair of ParticipAction, Chair of the Alberta Economic Development Authority, President of the Calgary Chamber of Commerce and a member of the Canadian Football League Board of Governors and Chair of the Southern Alberta Institute of Technology Board of Governors. In 2004, he was appointed to the Order of Canada and in 2007 was inducted into the Alberta Order of Excellence.

Catherine M. Roozen
Alberta, Canada
Date of Birth: March 1956
Year appointed: 2014
Term expires: 2018

Principal Occupation During Past Five Years:
Chair, Cathton Investments Ltd. from 2009.

Skills and Experience:
Ms. Roozen holds a Bachelor of Commerce degree from the University of Alberta. She is Chair of Cathton Investments Ltd., as well as Director and Secretary of the Allard Foundation Ltd., and is a former Vice-President, Investments at Cathton Holdings Ltd. She is currently a Director at Melcor Developments Ltd. and Corus Entertainment Inc. She has also served as Vice President, Investments, at North West Trust Company, and has served on a number of other boards. In December 2015, Ms. Roozen was appointed to the Order of Canada.

Helen K. Sinclair
Ontario, Canada
Date of Birth: April 1951
Year appointed: 2008
Term expires: 2018

Principal Occupation During Past Five Years:
Chief Executive Officer, Bank Works Trading Inc. (satellite communications and business television) from 1996.

Skills and Experience:
Ms. Sinclair holds a Masters of Arts (Economics) degree from the University of Toronto and is a graduate of the Advanced Management Program at Harvard Business School. She is the founder and Chief Executive Officer of Bank Works Trading Inc. and its business television network (BCN.tv), and is a former President of the Canadian Bankers Association. She previously served as a Director at TD Financial Group and DH Corporation (formerly Davis + Henderson Corporation). She has also served as Senior Vice President, Planning and Legislation at Scotiabank, and on the boards of a number of public policy and adjudicative bodies. Ms. Sinclair has served on the human resources and compensation committees of TD Bank Financial Group, DH Corporation (previously as Chair), Canada Pension Plan Investment Board and McCain Capital.

Nizar Jaffer Somji
Alberta, Canada
Date of Birth: March 1959
Year appointed: 2015
Term expires: 2017

Principal Occupation During Past Five Years:
Chief Executive Officer, Jaffer Inc.; prior thereto President and Chief Executive Officer of Matrikon Inc. to June 2010.

Skills and Experience:
Mr. Somji graduated from the University of Birmingham with a Bachelor of Science degree in electrical engineering and holds a Master of Science degree in Chemical Engineering from the University of Alberta. Mr. Somji is the President and Chief Executive Officer of Jaffer Inc. and founder and former President and Chief Executive officer of Matrikon Inc. prior to it being acquired by Honeywell in 2010. He is currently a Chairman at Redline Communications Group Inc. and at Zafin Inc., a Director at Critical Control Energy Services Corp. and is on the University of Alberta Board of Governors.

Sheila C. Weatherill, C.M.
Alberta, Canada
Date of Birth: October 1945
Year appointed: 2002
Term expires: 2019

Principal Occupation During Past Five Years:
Senior Advisor at University of Alberta (post-secondary education) from January 2009; prior thereto, Independent Investigator to the Government of Canada from January 2009 to July 2009; prior thereto, President and Chief Executive Officer, Capital Health Authority (regional health authority) from 1996.

Skills and Experience:
Ms. Weatherill graduated from the University of Alberta in nursing. She holds an Honorary Doctor of Laws degree from the University of Lethbridge and an Honorary Bachelor of Arts degree from MacEwan University. Ms. Weatherill is former President and Chief Executive Officer of the Capital Health Authority and presently serves as Director of Canada Health Infoway, Inc. She is currently a Director at Shaw Communications Inc. She received the Alberta Centennial Medal, was appointed to the Order of Canada and was formerly a member of the Prime Minister’s Advisory Committee on the Public Service.

Director Independence

All members of the Board are independent, as the term is defined in National Instrument 58-101 – *Disclosure of Corporate Governance Practices* (NI 58-101). Under NI 58-101, a director is independent if he or she would be independent within the meaning of independence under National Instrument 52-110 – *Audit Committees* (NI 52-110). Essentially, a director is independent if he or she has no direct or indirect material relationship with the Corporation. A “material relationship” is a relationship that could, in the view of the Board, be reasonably expected to interfere with the exercise of a director’s independent judgment.

The Board determines annually whether each member of EPCOR’s Board is independent based on whether they, among other things, worked for EPCOR, had any immediate family member engaged in the employment of EPCOR, benefited from a business relationship with EPCOR that could reasonably be perceived to materially interfere with their independent judgment, or received remuneration from EPCOR other than remuneration for acting as a member of the Board and Board established committees of the Corporation.

<u>Chair of the Board</u>

Mr. Hugh Bolton is the Chair of the Board. Mr. Bolton, who is independent as the term is defined in NI 58-101, was appointed to this position on January 1, 2000. Mr. Bolton’s responsibilities as the Chair of the Board are set out in the Chair’s Terms of Reference, which have been formally adopted by the Board. The Chair reports to the City and is responsible for ensuring that the City receives accurate, relevant and timely information respecting the Board’s actions. As chief spokesperson for the Board, the Chair represents the Board’s views to, and reports back to the Board respecting communications with, the City.

The primary responsibilities of the Chair are to chair effective Board and shareholder meetings, monitor and oversee the strategic agenda of the Corporation and to provide leadership and advice respecting business planning processes, corporate governance and supporting material provided to the Board. Furthermore, the Chair shall ensure the responsibilities of the Board are well understood by the Board and management of the Corporation and that the boundaries between the Board and management are clearly understood and respected.

<u>Outside Directorships</u>

The following directors of EPCOR are presently directors of other issuers that are reporting issuers (or the equivalent) in Canada or in a foreign jurisdiction:

Mr. Bolton	Director of WestJet Airlines Ltd.
Mr. Mitchell	Director of AltaLink Management Ltd., which is the general partner of AltaLink L.P. and trustee of Northview Apartment Real Estate Investment Trust.
Ms. Roozen	Director of Melcor Developments Ltd. and Corus Entertainment Inc.
Mr. Somji	Director of Redline Communications Group Inc. and Critical Control Energy Services Corp.
Ms. Weatherill	Director of Shaw Communications Inc.

For a portion of 2016, there was one interlocking directorship resulting from the directors of EPCOR acting as directors of other issuers: Mr. Bolton is currently and until May, 2016 Mr. Laurence (Larry) Pollock was a director of WestJet Airlines Ltd., however, Mr. Pollock`s term as a director of the Corporation ended on May 6, 2016. The Board had determined that this interlocking directorship did not impact the ability of these directors to act in the best interests of the Corporation.

There is one interlocking relationship resulting from Mr. Culmone being the Executive Vice President, Finance and Chief Financial Officer of Shaw Communications Inc. and Ms. Weatherill acting as a director of Shaw Communications Inc. The Board has determined that this interlocking relationship does not impact the ability of these directors to act in the best interests of the Corporation.

<u>Material Interests</u>

Directors and executive officers of the Corporation are regularly asked to disclose in writing any material interest he or she has in a material contract or transaction with the Corporation, whether or not it is a current or proposed contract or transaction, or have the interest entered into the minutes of a Board meeting, including its nature and extent. When a director has a material interest, the director must refrain from participating in any discussion or vote on the matter. In practice, a director with a material interest recuses himself or herself from the Board meeting when a discussion or vote takes place on such matter.

Board Meetings

The Board holds regularly scheduled meetings as well as *ad hoc* meetings from time to time. The Board, which consists only of independent members as defined by NI 58-101, regularly meets without management present for a portion of its meetings. The Board may excuse directors and members of management from all or a portion of any meeting where a potential conflict of interest arises or where otherwise appropriate.

In 2016, the attendance of directors at Board meetings was as follows:

Name	Number of Meetings	Attendance
Hugh J. Bolton	8 of 8 meetings	100%
Vito Culmone	8 of 8 meetings	100%
Robert G. Foster	8 of 8 meetings	100%
Allister J. McPherson	8 of 8 meetings	100%
Douglas H. Mitchell	8 of 8 meetings	100%
Laurence M. Pollock(1)	3 of 3 meetings	100%
Catherine M. Roozen	8 of 8 meetings	100%
Helen K. Sinclair	8 of 8 meetings	100%
Nizar Jaffer Somji	8 of 8 meetings	100%
Sheila C. Weatherill	8 of 8 meetings	100%

(1) Mr. Pollock retired on May 6, 2016.

Orientation and Continuing Education

EPCOR has procedures in place for the orientation of new directors. New directors meet with the President and Chief Executive Officer, the Chief Financial Officer and the Chair of the Board in order to improve their understanding of the Corporation as well as the overall industries within which the Corporation participates. New directors are also provided the option of receiving briefings from members of senior management of the Corporation and the Corporation's external auditor.

In addition, all directors are provided with a Board of Directors Governance Manual, which contains detailed information about EPCOR's business, Board and committee terms of reference, individual director terms of reference, authority matrices, corporate structure, governance, policies and other related matters of interest to the directors. This Board of Directors Governance Manual, which is available to all directors electronically, is updated as the documents included in it are amended or replaced. Furthermore, all directors are also provided with the opportunity to annually tour at least one of the Corporation's sites that is illustrative of each of the various types of facilities and plants owned and operated by the Corporation.

The Corporate Governance and Nominating Committee's (CG&N Committee) Terms of Reference require that the CG&N Committee review, monitor and make recommendations to the Board regarding new director orientation and ongoing development of existing Board members. The Board, in consultation with senior management, identifies discussion topics for its annual planning retreat. Regular presentations are organized for the Board by senior management with respect to subjects relevant to the operations of the Corporation. In addition, with respect to developments in the law regarding directors' obligations and regulatory developments that may impact the Corporation's operations, EPCOR's General Counsel keeps informed of such developments and updates the Board as necessary. The Corporation also makes available $1,500 per year or $6,000 every four years for each director towards professional development courses of a general nature that will be of benefit to the Corporation. This contribution can be used for any relevant expenses related to the pursuit of the director's education, which expenses may include conference fees, membership dues, registration fees, materials, reference books and similar expenses.

Ethical Business Conduct

The Corporation has adopted a written ethics policy (the Ethics Policy), applicable to all employees of EPCOR and its Canadian subsidiaries, including their directors. The Board has oversight and control over the policy including governance over all material changes to and deviations from the policy. A summary report of all ethics investigations are included in the quarterly Litigation and Ethics Report provided to the Audit Committee. A copy of the Ethics Policy can be obtained from EPCOR's Corporate Secretary upon request or from EPCOR's website at www.epcor.com.

EWUS has adopted a written ethics policy (the U.S. Ethics Policy), applicable to all employees of EWUS and its subsidiaries, including their directors. The board of directors of EWUS has oversight and control over the U.S. Ethics Policy including governance over all material changes to and deviations from the U.S. Ethics Policy. A summary report of all ethics investigations are included in the quarterly Ethics Report that EWUS' Ethics Officer provides to the board of directors of EWUS and is also appended to the quarterly Litigation and Ethics Report provided by EPCOR's Ethics Officer to EPCOR's Audit Committee. A copy of the U.S. Ethics Policy can be obtained from EPCOR's Corporate Secretary upon request or from EPCOR's website at www.epcor.com.

The Corporation promotes a culture where anyone can speak openly about ethical concerns without fear of reprisal. Employees can raise a concern with their manager or a member of senior management, or report a concern or possible violation through EPCOR's Integrity Hotline (for concerns or violations with respect to the Ethics Policy) or EPCOR's Compliance Hotline (for concerns with the U.S. Ethics Policy). These hotlines operate in a fashion that ensures confidentiality. Ethics training for employees and the Board is conducted bi-annually.

The Corporation investigates complaints thoroughly and promptly. An investigation may involve review of documents and interviews of employees, contractors or agents in order to corroborate facts. The Corporation's goal is to keep every complaint, investigation and resolution as confidential as possible, and take corrective action as appropriate. A written report is completed on every investigation process and the outcome is maintained in the Corporation's files. All of the Corporation's employees are required to participate in ethics training every two years.

Nomination of Directors

The Board is a competency-based board with diverse skills and business and professional backgrounds. Suitability as a director is based on a balance of personal characteristics, applicable experience, specialized knowledge, technical skills and affiliations. The CG&N Committee keeps matrices, which identify the skills, expertise, knowledge, education and experience of the existing Board and areas where the Board requires certain skills, expertise, knowledge, education and experience. EPCOR's Board Recruitment and Appointment Procedure was approved by the City on November 9, 2012. In accordance with that procedure, new candidates are identified by the CG&N Committee with a view to matching their attributes with the attributes collectively required by the Board.

The CG&N Committee's Terms of Reference and the Board's Recruitment and Appointment Procedure include the requirement to consider gender diversity when recruiting new Board members. When identifying and nominating Board candidates, the CG&N Committee and the Board consider the level of representation of women on the Board but do not set targets regarding such. Presently, 33% of the Board is comprised of women.

City of Edmonton Council represents the City as sole Shareholder of the Corporation and is responsible for the appointment and re-appointment of the Chair and directors of the Corporation. The candidates recommended by the Board may then be interviewed by the Shareholder, which then appoints the new Board members. The Corporation does not impose a mandatory retirement age for Board members. The Corporation's By-Law specifies a maximum 15-year term for directors, unless the Shareholder waives the restriction.

Director and Executive Compensation

The CG&N Committee's Terms of Reference prescribe regular review of director compensation. The CG&N Committee considers time commitment, comparative fees, and responsibilities related to remuneration for directors. On the advice of the CG&N Committee, the Chair of the Board makes recommendations to the City in order to determine directors' compensation. The CG&N Committee receives independent advice in respect of directors' compensation from Willis Towers Watson Public Limited Company (WTW).

The compensation of the members of the executive team, including the Chief Executive Officer's compensation, is approved by the Board on the basis of recommendations from the Human Resources & Compensation (HR&C Committee). As further described herein, among other things, through use of an independent executive compensation consultant, considering comparable market data from third party surveys to provide an initial reference point for assessing present and determining future compensation levels, and having the Board approve director and officer compensation policies recommended by the HR&C Committee, the Board ensures that the HR&C Committee has in place an objective process for determining compensation for directors and officers.

Standing Committees

The Board has established the following standing committees: (i) Audit Committee; (ii) HR&C Committee; (iii) Environment, Health & Safety Committee (EH&S Committee); and (iv) CG&N Committee. The members of the four standing committees as of the date of this AIF were as detailed below:

Directors	Audit Committee	HR&C Committee	EH&S Committee	CG&N Committee
Hugh J. Bolton	Ex-officio	Ex-officio	Ex-officio	Ex-officio
Vito Culmone	Chair	✓		
Robert G. Foster			Chair	✓
Allister J. McPherson		Chair		✓
Douglas H. Mitchell				Chair
Catherine M. Roozen	✓		✓	
Helen K. Sinclair	✓		✓	
Nizar Jaffer Somji	✓	✓	✓	
Sheila C. Weatherill		✓		✓

The functions of the four standing committees are as follows:

Audit Committee

The Corporation's Audit Committee operates under the "Audit Committee Terms of Reference" attached as Appendix I to this AIF.

HR&C Committee

The HR&C Committee assists the Board in fulfilling its responsibilities relating to human resources matters including compensation, evaluation and succession of employees of the Corporation.

EH&S Committee

The EH&S Committee monitors, evaluates, advises, makes recommendations and has general oversight on matters relating to the impact of the operations of the Corporation on the environment and workplace health and safety of its employees.

CG&N Committee

The Corporation's CG&N Committee ensures appropriate structures, processes and policies are in place to address governance matters and maintain compliance with governance guidelines. It also manages the procedures related to the appointment of new directors, the re-appointment of existing directors and the performance and effectiveness of the Board, its committees and individual directors. The CG&N Committee identifies new candidates and recommends appointments to the Board for further recommendation to the Shareholder.

Assessments

The CG&N Committee reviews, monitors and makes recommendations on the effectiveness of the Board. Directors are annually surveyed on the effectiveness of the Board and its committees. With a view to obtaining constructive feedback, the Board annually considers the manner in which it will monitor its effectiveness, its committees and individual Board members. In the past, the Board has chosen to use varying methods, including: (i) retaining an external consultant to interview all members of the Board; (ii) having the Chair of the Board or the CG&N Committee interview all members of the Board; and (iii) having all members of the Board complete confidential surveys and evaluations with respect to each member of the Board. With respect to each of the evaluation methods, the results are compiled and discussed by the Board as a whole. Evaluations focus on individual Board members' attendance, preparation and contributions made during the meetings as well as other matters germane to the performance of the Board, its committees and individual directors.

AUDIT COMMITTEE INFORMATION

AUDIT COMMITTEE MANDATE

The Corporation's Audit Committee operates under the "Audit Committee Terms of Reference" attached as Appendix I to this AIF.

COMPOSITION OF THE AUDIT COMMITTEE

The current members of the Audit Committee are outlined above under Standing Committees. Each of the members of the Audit Committee is considered "financially literate" within the meaning of NI 52-110. The education and experience of each director relevant to the performance of a director's duties as a member of the Audit Committee is outlined above under Directors of the Corporation.

POLICIES AND PROCEDURES FOR THE ENGAGEMENT OF AUDIT AND NON-AUDIT SERVICES

Under its Terms of Reference, the Audit Committee is required to pre-approve all non-auditing services to be performed by the external auditors in relation to the Corporation and its subsidiaries. Annually, the external auditors will submit their annual work plan to the Audit Committee, including the nature and scope of any audit-related advisory services (as requested by management) planned for the upcoming year. Once that plan is pre-approved by the Audit Committee, management has the authority to schedule the pre-approved services.

Any unplanned audit-related advisory services or other advisory services are presented for pre-approval at the regularly scheduled meetings of the Audit Committee. If, due to timing issues, the pre-approval of unplanned non-audit services must be expedited and it is not practically possible to wait until the next regularly scheduled Audit Committee meeting, the Chair of the Audit Committee has the delegated authority, on behalf of the Audit Committee, to pre-approve the unplanned non-audit services when the individual engagement fees are projected to be less than $50,000 subject to an annual maximum approval limit of $200,000. The unplanned non-audit services pre-approved by the Chair of the Audit Committee are then reviewed at the next Audit Committee meeting.

AUDITOR OF THE CORPORATION AND AUDITOR'S FEES

KPMG LLP, Chartered Accountants has served as the Corporation's auditing firm continuously since 1995. Fees billed by KPMG LLP to the Corporation and its subsidiaries in the years ended December 31, 2016 and December 31, 2015 were approximately $0.9 million and $1.1 million, respectively, as detailed below.

($ millions)	Year Ended December 31, 2016	Year Ended December 31, 2015
Audit fees	$0.9	$0.9
Audit-related fees	0.0	0.1
All other fees	0.0	0.1
Total	$0.9	$1.1

Audit fees

Audit fees billed by KPMG LLP were for professional services rendered for the audit and review of the consolidated financial statements of the Corporation and the financial statements of certain subsidiaries or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents.

Audit-related fees

Audit-related fees billed by KPMG LLP are for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not reported under audit fees listed above. These services include the auditing of financial information contained in securities documents and audit procedures pertaining to acquisitions and joint venture related projects.

All other fees

"All other fees" as listed in the table above include fees billed by KPMG LLP for services other than audit fees, audit-related fees and tax fees including control effectiveness testing.

COMPENSATION DISCUSSION AND ANALYSIS

The purpose of this Compensation Discussion and Analysis is to provide an overview of EPCOR's executive compensation philosophy, objectives and processes, and describe the compensation decisions made in respect of EPCOR's Named Executive Officers (NEOs). In 2016, EPCOR's NEOs were: Stuart Lee, President and Chief Executive Officer; Guy Bridgeman, Senior Vice President and Chief Financial Officer; Joseph Gysel, Senior Vice President, EPCOR Water USA (President, EWUS); Stephen Stanley, Senior Vice President, Commercial Services; and Frank Mannarino, Senior Vice President, Electricity Services.

COMPENSATION GOVERNANCE

HR&C Committee

Mandate

The role of the HR&C Committee with respect to compensation is to:

- Oversee and recommend for approval by the Board, EPCOR's executive compensation philosophy including all forms of compensation for the Chief Executive Officer and each member of the executive team;
- Approve and monitor the general compensation policies and plans for EPCOR; and
- Review and approve the performance measures, payout ranges and resultant incentive plan payouts to ensure risks have been appropriately accounted and adjusted for in alignment with the Corporation's risk tolerance.

In evaluating the degree to which performance measures and targets have been achieved under applicable incentive plans and in determining resulting payouts, the Board applies informed judgment to look beyond the formal measures to consider other elements it believes have significantly impacted overall corporate performance. Such other elements include the consideration of events or circumstances that are outside of management's direct influence or control and management's actions in respect of unplanned events or circumstances.

The HR&C Committee Terms of Reference establish its purpose, responsibilities and membership. During 2016, the HR&C Committee met three times. The HR&C Committee undertakes an objective process for determining compensation by holding in-camera sessions at the end of meetings, without management present. Any decisions made during such sessions are recorded in the minutes of the meeting.

Composition of the HR&C Committee

The current members of the HR&C Committee are outlined above under Standing Committees. The education and experience of each director relevant to the performance of a director's duties as a member of the HR&C Committee is outlined above under Directors of the Corporation.

Independent Executive Compensation Consultant

Since 2001, the HR&C Committee has retained the services of an independent executive compensation consultant, WTW, to provide advice to the HR&C Committee on levels of compensation in the competitive market in which the Corporation operates and on other compensation and governance-related matters such as total compensation benchmarking, comparator group selection and incentive plan design and calibration. WTW provides advice to the HR&C Committee through an individual employed by WTW (the Executive Compensation Consultant).

While WTW provides consulting advice and administrative support to the management of the Corporation on pension, general compensation surveys and regulatory rate case matters, WTW was also engaged by the HR&C Committee, independent of management. The Corporation and WTW took several steps to maintain the independence of the Executive Compensation Consultant. Although the HR&C Committee concluded that there were adequate safeguards in place to ensure the independence of the Executive Compensation Consultant's advice and recommendations, the HR&C Committee recently decided to engage Hugessen Consulting Incorporated (Hugessen), to provide exclusive executive compensation advice to the Committee. Hugessen began providing advice to the HR&C Committee in the first quarter of 2017.

WTW has served as a consultant to management of the Corporation continuously for the past 20 years. The services provided to management of the Corporation and the related costs are subject to the Corporation's planning, budgeting and approval processes and costs related to these services are not pre-approved by the HR&C Committee. WTW will continue to provide consulting services to management.

Fees billed by WTW to the Corporation and its subsidiaries in the years ended December 31, 2016 and December 31, 2015 were $0.29 million and $0.45 million, respectively, as detailed below.

Executive Compensation – Related Fees

($ millions)	**Year Ended December 31, 2016**	**Year Ended December 31, 2015**
Fees paid to Executive Compensation Consultant(1)	$0.20	$0.21
All Other Fees		
Pension and Benefits(2)	0.04	0.07
Regulated Rate Applications(3)	0.00	0.13
Other fees(4)	0.05	0.04
Total	**$0.29**	**$0.45**

(1) Includes advice to the HR&C Committee on levels of compensation in the competitive market in which the Corporation operates and on other compensation matters such as total compensation benchmarking, comparator group selection, incentive plan design and calibration, and trends in executive compensation practices and governance.
(2) Includes actuarial and consulting services related to pension plan design, pension benefit calculations and benefit survey participation.
(3) WTW provides advice, evidence and appears as an expert witness (when required) in respect of EPCOR's EDTI and Energy Services rate application proceedings before the AUC.
(4) Includes management compensation surveys and accounting and actuarial reporting for the Corporation's annual consolidated financial statements.

Compensation Approval Process

In determining the compensation arrangements for each of the Corporation's executives, the HR&C Committee considers a comprehensive market analysis. The analysis includes market data prepared by WTW for similar positions within the comparator group, as discussed in further detail in the Comparator Group section below, and the Chief Executive Officer's recommendations for his direct reports, including all of the other NEOs.

The HR&C Committee reviews the various compensation elements for individual executives and in aggregate to evaluate internal equity and seek alignment with program objectives and alignment to the Corporation's overall business strategies. The HR&C Committee then makes recommendations on all executive compensation elements to the Board for approval. The Board also ensures that the individual performance objectives for the Chief Executive Officer and other NEOs align with the Corporation's business objectives and reflect performance areas that are specific to each role when it reviews and approves his or her total compensation.

Risk Mitigation

EPCOR is primarily a rate regulated entity with very limited opportunities for excessive risk taking. The HR&C Committee is responsible, with assistance from its advisors and management, for identifying the potential risks associated with the compensation policies and practices and for developing and monitoring compliance with such policies and practices.

In 2016, the HR&C Committee requested the Executive Compensation Consultant to review the Corporation's compensation policy and programs for its executive team and the related governance structure and to assess any potential risk implications. The Executive Compensation Consultant concluded that there did not appear to be significant risks arising from the programs and structure that were reasonably likely to have an adverse effect on the Corporation.

The HR&C Committee has implemented a range of compensation policies and practices to incent the right behaviours and prevent excessive or undue risk-taking by management, as highlighted in the table below.

Policy/Practice	Description
Compensation Philosophy	Compensation is designed and delivered in accordance with a detailed compensation philosophy.
Ethics & Compliance Policies	Management rigorously enforces EPCOR's Ethics Policy. Quarterly compliance reports are submitted to EPCOR's Compliance Officer by all executive and senior officers indicating compliance with EPCOR policies in their area of responsibility (or the nature of any non-compliance).
Regulatory Review	External rate regulators review operating forecasts (which include compensation) and capital programs as part of rate tariff proceedings.
Structured Review and Approval Process	All aspects of the executive compensation program, including the compensation policy, annual compensation budgets, incentive metrics and executive pay levels are presented to the HR&C Committee for review and recommendation to the Board for approval. With respect to short-term and mid-term incentive plans: • Actual performance against short-term incentive metrics is audited internally. • The annual capital expenditure budget (including sustaining capital) and larger growth-related capital projects or investments that impact mid-term incentive payout opportunities are approved annually by the Board.
Independent Compensation Advice	The HR&C Committee retains Hugessen (WTW prior to 2017) to assist and guide them in executive compensation and benefit matters.
External Benchmarking	Total compensation is targeted at the 50th percentile of the market, based on a comparator group that is reviewed by the HR&C Committee. In addition, management participates in multiple external salary survey programs to obtain and maintain current market data, which is presented to the HR&C Committee in conjunction with the annual compensation cycle.
Pay-for-Performance	Approximately 23% of the executive team's total direct compensation is delivered through short-term variable pay and 31% through longer-term variable pay, which provides strong pay-for-performance alignment over multiple time periods.
Multiple Performance Metrics	The Short-term Incentive Plan (STIP) is designed using a scorecard approach measuring a series of financial, safety, operational and customer metrics thereby minimizing the risk that one metric will overly influence payout results. Mid-Term Incentive Plan (MTIP) metrics measure capital and income growth to help monitor performance of capital investment decisions.
Robust Target Setting Process	Performance targets are set in consideration of multiple factors, including historical trends, with a view to raising performance expectations on an annual basis.
Incentive Funding & Payout Caps	The amount of funding available for distribution under the STIP is capped at a maximum of 200% of aggregate target awards. Further, individual awards under the MTIP are capped at 200% of target.
Application of informed judgment	When determining final compensation, the HR&C Committee and the Board may apply informed judgment to adjust the value of awards. This ensures that the awards appropriately take account of associated risks and other unexpected circumstances that arise during the year.
Clawback Policy	Allows the Board to seek reimbursement of full or partial compensation applicable to short-term or mid-term incentive awards under specified scenarios for the executive team.
Status Reports and Communication	The HR&C Committee and the Board receive regular updates in respect of all aspects of compensation program design. Specifically: • The HR&C Committee receives updates on EPCOR's performance against STIP and MTIP performance targets and estimated payout levels throughout the year. • Labour negotiating mandates are presented in advance to the HR&C Committee for review and approval and post-negotiation outcomes are presented to the HR&C Committee. • Post implementation reviews of capital investments and resultant profitability are conducted internally by management and presented to the Board for information.

After considering the potential risks associated with EPCOR's compensation program, including the Executive Compensation Consultant's review of the policies and practices outlined above, the Board believes that:

- EPCOR has the proper practices in place to effectively identify and mitigate potential risks; and
- EPCOR's compensation policies and practices do not encourage any employee to take inappropriate or excessive risks, and are not reasonably likely to lead to an event which would have a material adverse effect on the Corporation.

COMPENSATION PHILOSOPHY

Guiding Principles

EPCOR's compensation programs are grounded on principles that support the management of risk, ensuring management's plans and activities are prudent and focused on generating shareholder value within an effective risk control environment. The following principles form EPCOR's compensation philosophy:

Principle	Compensation Programs
Stakeholder Interests	• Recognize EPCOR's role as a significant Alberta employer and service provider, taking into account the unique interests of its shareholder, employees, customers, and regulatory stakeholders.
Link to Strategy	• Link to the successful execution of EPCOR's business strategy and support its values: (i) We put safety first in everything we do; (ii) We act with integrity; (iii) We work as a team; (iv) We are trusted by customers; (v) We create shareholder value; and (vi) We are environmental leaders.
Long-term Value Creation	• Support strategic business objectives of prudent, sustainable and profitable growth while funding shareholder dividends at acceptable levels.
Pay-for-Performance	• Promote a performance culture that rewards superior corporate, business unit and individual performance and results. • Align compensation costs with affordability and business growth.
Career Oriented	• Reinforce a long-term career orientation that reflects the deep technical skill sets required to support key focus areas.
Market Competitive	• Support the attraction, retention and engagement of high performing talent through competitive compensation opportunities.
Simple and Integrated	• Are simple to understand and administer, and communicated in a way that the integrated value of monetary and non-monetary rewards is understood.

Target Competitive Positioning

Individual compensation arrangements are designed to be market-competitive in order to attract, engage and retain highly qualified leaders. Market competitiveness is defined as maintaining, in aggregate, a 50th percentile (or median) target total compensation level relative to EPCOR's approved comparator groups, consisting of organizations with similar operations, degrees of complexity and employee skill sets. Total actual compensation may be positioned above the 50th percentile in the event of superior performance by the Corporation, business unit and / or the individual. Where performance does not meet some or all of the stated objectives, total actual compensation could be positioned below the 50th percentile.

Comparator Groups

For purposes of benchmarking market compensation levels and assessing alignment with its stated competitive positioning philosophy, EPCOR has developed compensation comparator groups (comparator groups) that represent the labour market in which the organization competes for talent. As part of its annual compensation review, the Corporation considers comparator group data from third party surveys to provide an initial reference point for assessing present and determining future compensation levels.

The composition of the Corporation's comparator groups is reviewed annually for continued relevance by WTW and the HR&C Committee. The guiding principles for consideration of businesses for inclusion in the comparator group are:

Principles	Canada	U.S.
Industry	Energy utilities and pipeline organizations.	Utilities and other industries that either have capital intensive, engineering and / or regulated aspects.
Market For Talent	Resource based organizations, particularly in the Alberta energy sector.	Similar market where Water USA operates.
Company Size	Organizations of all sizes for skilled professionals and executives.	Revenue criteria of 0.5x to 3x to current EWUS revenue.
Geography	Operations in Western Canada.	Operations in the Lower Mountain region of the U.S. (i.e. Arizona, Colorado, New Mexico, or Utah).
Ownership Structure	All corporate structures.	
Organizational Complexity	Regulated and non-regulated business components.	
Business Characteristics	Capital intensive organizations.	

Based on the above criteria, the comparator group used to assess Canadian pay levels in 2016 for industry specific roles was comprised of the following organizations:

- Alberta Electric System Operator
- Alliance Pipeline Limited Partnership
- AltaGas Ltd.
- AltaLink Management Ltd.
- ATCO Group (ATCO Electric, ATCO Power and ATCO Gas)
- British Columbia Hydro and Power Authority
- Capital Power Corporation
- City of Medicine Hat (Hydro Division)
- Enbridge Inc.
- ENMAX Corporation
- FortisAlberta Inc.
- FortisBC (Terasen Gas)
- Inter Pipeline
- Kinder Morgan Canada
- SaskEnergy
- SaskPower
- Spectra Energy Transmission
- TransAlta Corporation
- TransCanada Corporation

Based on the above criteria, the comparator group used to assess Canadian pay levels in 2016 for shared services and non-industry specific roles was comprised of the following organizations in addition to the organizations listed immediately above that were used to determine pay levels for industry specific roles:

- Agrium Inc.
- Bruce Power
- Cogeco Inc.
- Dow Chemical
- Energy Resources Conservation Board
- Ericsson Canada Inc.
- Independent Electricity System Operator
- INEOS Canada Partnership
- MacDonald, Dettwiler & Associates
- Methanex
- NOVA Chemicals
- Ontario Power Generation
- ShawCor
- Siemens Canada
- Sierra Wireless
- Stantec Inc.
- TELUS
- Toronto Hydro Electric System

Based on the above criteria, the comparator group used to assess U.S. pay levels in 2016 was comprised of the following organizations:

- Arcadis NV
- Arizona Water Company
- Atmos Energy Corporation
- Black Hills Corporation
- CH2M Hill Companies Ltd.
- Colorado Springs Utilities
- El Paso Electric Company
- Global Water Resources Inc.
- Level 3 Communications Inc.
- Pinnacle West Capital Corporation
- Platte River Power Authority Inc.
- PNM Resources Inc.
- Questar Corporation
- Salt River Project Agricultural Improvement and Power District
- Southwest Gas Corporation
- Tucson Electric Power Company Inc.
- UNS Energy Corporation
- Vectrus Inc.

Market survey results reviewed by the HR&C Committee may be prepared using a methodology generally referred to as “size-adjusting”. Since organization size is often a key factor in determining executive compensation levels, regression analysis is used when appropriate to “size-adjust” the market data using a variable such as annual revenue to account for differences in the size and complexity of companies in the comparator groups and those of the Corporation. This technique enables compensation practices from a range of organizations within the Corporation’s targeted industry sector to be analyzed and considered. The HR&C Committee also considers “raw” unadjusted market data as a secondary reference point and / or where robust size-adjusted data is unavailable. In 2016, EPCOR was positioned around the median of the Canadian comparator group based on revenue.

Compensation Elements and Target Mix

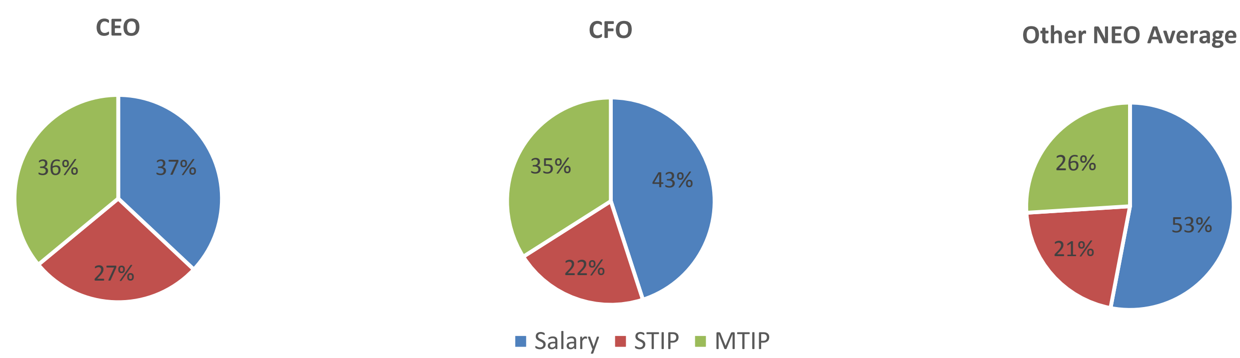
The compensation philosophy has guided the development of an executive compensation model that includes a mix of base salary, short-term incentives, mid-term incentives and pension and benefits.

Base salary	STIP	MTIP	Benefits and Pension
Fixed level of compensation based on specified accountabilities.	Designed to reward executives for achievement of annual corporate, business unit and individual targets that support the Corporation’s strategic direction.	Designed to align executive and shareholder interests by focusing executives on the Corporation's longer-term strategic objectives and sustained value creation.	Market competitive health, retirement and other benefits.

Total direct compensation represents the combined value of fixed compensation and performance-based variable compensation. For executives, a significant focus is on performance-related compensation (short and mid-term incentives). The relative weighting on base salary, short and mid-term incentives for each executive takes into account the executive's role and level in the Corporation, his or her ability to influence short and longer-term business results and the compensation mix for similar positions in the competitive market.

To assist in determining the values to be allocated to each compensation element for the NEOs, the HR&C Committee reviews competitive market data for similar positions within EPCOR's comparator group, including data provided by the Executive Compensation Consultant.

The pie charts below outline the target total direct compensation mix for the CEO, CFO and average of other NEOs in 2016:



2016 NEO COMPENSATION DECISIONS

STIP Compensation

The Corporation’s STIP is designed to place focus on the importance of achieving safety metrics while continuing to recognize business unit operational efficiency, customer and financial performance metrics. The STIP also allows management to allocate STIP payments on a discretionary basis (taking into account individual performance) within a budget both determined and funded by corporate and business unit results.

<u>2016 STIP Target Awards</u>

NEOs are eligible for annual target awards under the STIP, as recommended by the HR&C Committee and approved by the Board. Awards are payable the following year, subject to the achievement of corporate, business unit and individual performance objectives.

Individual target award levels are expressed as a percentage of salary and generally align with the median of the comparator group for positions with similar responsibilities to those of the Corporation. In 2016, NEO STIP target award levels were 75% for Mr. Lee, 50% for Dr. Bridgeman and 40% for other NEOs. The STIP target award represents the amount that could be paid if performance objectives were achieved at target levels. Actual STIP payouts may be above or below target award levels depending on plan funding (as described in detail below) and individual performance results. The aggregate payment of individual STIP awards cannot exceed the overall approved plan funding.

2016 STIP Plan Funding

STIP awards are funded based on a scorecard approach which considers performance against business unit and / or consolidated net income and operational business unit objectives. The aggregate amount of STIP funds available for payment to eligible employees is derived based on two pools, as follows:

Pool A
"Managing the Business"
Up to 100% of target STI

+

Pool B
"Financial Profitability"
33% of the amount Corporate Net Income exceeds Target
Up to 100% of target STI - (maximum of Pool A result)

=

Total Available STI Funding
Up to maximum 200% of target STI

STIP Pool A is established based on performance against pre-determined financial, safety, operational efficiency and customer service metrics at the business unit or consolidated level, which are approved by the HR&C Committee of the Board of Directors annually. For 2016, the STIP Pool A performance measures and respective weights were as follows:

Performance Metric	2016 STIP Pool A Weighting						
	Water Canada	Water USA	Electricity Operations	Technologies	Energy Services	Commercial Services	Corporate*
Consolidated Net Income	-	-	-	-	-	10%	10%
Business Unit Net Income	10%	10%	10%	10%	10%	-	-
BU Metrics: • Safety • Operational Efficiency • Customer Service	 30% 30% 30%	 30% 30% 30%	 30% 30% 30%	 30% 30% 30%	 30% 30% 30%	 30% 40% 20%	 30% 60% -

* *Corporate consists of all corporate departments (except Finance and HSE employees embedded in business units) reporting to the SVP & CFO, SVP Corporate Services, General Counsel & Corporate Secretary and Director, HSE. The Chief Executive Officer's performance is based on the average results achieved by his direct reports.*

Each metric is evaluated relative to a pre-determined performance scale which provides for a payout of 50% of target at threshold (minimum) performance levels, 100% of target at target performance levels and 150% of target at stretch (maximum) performance levels. No amount is payable for a given metric if threshold performance is not achieved.

Overall performance is determined using aggregate results for all metrics. To recognize the importance of safety as a key component of the Corporation's culture, safety results below target cannot be offset by higher performance of one of the other performance metrics. As such, Pool A funding will reflect the degree to which a specific safety metric falls below target. Further, maximum funding for STIP Pool A is capped at 100% of target (being the sum of target STIP amounts for all employees eligible to participate in the corporate STIP).

STIP Pool B is triggered and funded if actual Consolidated Net Income exceeds the pre-determined target level. Up to 33% of the excess Consolidated Net Income achieved between target and stretch performance levels may be allocated to STIP Pool B. However, any allocated amount is subject to a cap of 100% of the aggregate funding for STIP Pool A. This approach reinforces the importance of growing the business and maximizing EPCOR's overall profitability and shareholder return.

2016 STIP Awards

Actual 2016 STIP awards for each NEO reflect a combination of corporate, business unit and individual performance achievement, as follows:

- Corporate Performance – The Consolidated Net Income performance objective is intended to reflect the executives' responsibilities, through the management of their respective business units or corporate departments, towards the Corporation achieving its short-term profitability objective. Consolidated Net Income for STIP purposes is calculated based on net income excluding any income, gains, losses or adjustments related to its financial interest in Capital Power as well as certain unrealized gains and losses related to interest rate swaps and other financial derivatives, and provincial transmission flow-through impacts. Actual 2016 Consolidated Net Income for STIP purposes was $242.16 million, relative to a target of $235.01 million, resulting in a corporate performance factor of 103.04% of target;

- Business Unit Performance – The NEOs are accountable for the performance of their specific business units. Accordingly, the overall STIP pool funding is allocated to each business unit based on overall financial and operational business unit results (safety, operational efficiency and customer service). In 2016, business unit funding allocations ranged from 90.36% - 117.35% of target; and

- Individual Performance – Individual executive performance objectives are pre-established through EPCOR's performance management program and are intended to align with annual corporate objectives and each NEO's respective responsibilities. Although NEOs are accountable for the performance of their specific business units, they have common key accountabilities including the following:
  - Provide input to the EPCOR strategic plans and directions, ensure an appropriate understanding of the EPCOR strategy throughout the business unit and ensure ongoing effective positioning and appropriate relationships between that business unit and the rest of EPCOR; and

  - Formulate and implement business plans and strategies to provide for profitable operations, to meet short-term objectives and to ensure long-term corporate growth and success. This includes ensuring the required organizational structure and achieving the required outcomes with time spans (longest target completion time) ranging from 5 years to 10 years.

Individual 2016 STIP performance objectives and results for each NEO were as follows:

Name	Individual Performance Objectives for 2016	2016 Results
Stuart Lee	• Develop and execute EPCOR's long-term plan. • Develop and foster a zero injury safety culture. • Deliver on 2016 operating budget including dividend payment. • Develop and coach senior management talent. • Maintain shareholder and customer relations.	Met and in some cases exceeded expectations.
Guy Bridgeman	• Deliver cost effective financing for the business. • Deliver timely accurate financial reporting. • Develop and foster a zero injury safety culture. • Deliver appropriate cash management and treasury functions. • Deliver prudent tax planning and tax compliance. • Develop and coach senior management talent. • Oversee and manage Internal Audit and Enterprise Risk Management functions. • Oversee the Energy Services business unit. • Lead the Corporate long-term strategic planning process.	Met and in some cases exceeded expectations.
Joseph Gysel	• Produce and deliver water to customers in the U.S. Southwest in a safe, environmentally responsible, reliable and competitively priced manner. • Meet all operating and financial targets; focusing on lower operating costs and capital investment optimization.	Met and in some cases exceeded expectations.

	• Support the acquisition implementation, growth and expansion of the U.S. operations. • Develop and foster a zero injury safety culture. • Provide Water Services leadership in the U.S. Southwest through coaching and staff development, succession planning and thought leadership in the water business. • Direct the Encor rollout and operations.	
Stephen Stanley	• Lead Commercial Services business unit, developing growth objectives and deliver on opportunities identified for 2016. • Meet all operating and financial targets for Technologies and Commercial Services. • Develop and foster a zero injury safety culture. • Lead reorganization of Technologies with focus on core operations and smart growth. • Ensure the Regina Wastewater Project remains on time and on budget.	Met and in some cases exceeded expectations.
Frank Mannarino	• Produce and deliver electricity to customers in Edmonton in a safe, environmentally responsible, reliable and competitively priced manner. • Meet all operating and financial targets. • Lead Distribution and Transmission operations to drive efficiencies and build technical operations depth. • Develop and foster a zero injury safety culture. • Implement technologies to support operational excellence; OMS / DMS, AMI and fleet telematics. • Maintain and improve customer service and relationships with key stakeholders.	Met and in some cases exceeded expectations.

Performance against individual objectives is reviewed following the completion of the fiscal year and each NEO receives a performance rating reflecting the degree to which business unit objectives and individual performance were achieved. Individual performance ratings are used to determine the overall STIP award for each NEO.

The table below summarizes the STIP result and payout for each executive for 2016:

Executive	2016 Base salary (annualized) (CAD$)	STIP Target Award (% of base salary)	STIP Result (% of Target)	STIP Payment [(1)] ($)
Stuart Lee	600,000	75	138	620,000
Guy Bridgeman	370,996	50	142	263,407
Joseph Gysel[(2)]	430,091	40	142	244,292
Stephen Stanley	311,220	40	101	124,488
Frank Mannarino	274,275	40	117	128,361

(1) Represents STIP award (in Canadian currency) earned for 2016 performance and paid in 2017.
(2) All compensation is reported in Canadian currency. Joseph Gysel was paid in U.S. currency with all U.S. dollars paid converted to Canadian currency using the average Canada / U.S. exchange rate as used in preparing the Corporation's consolidated financial statements for the year ended December 31, 2016. The average exchange rate was USD $1 to CDN $1.3256 in 2016.

MTIP Compensation

The Corporation's MTIP rewards for sustained value creation and dividend growth and is designed to align the longer-term interests of NEOs with those of the shareholder. The MTIP emphasizes the efficient management of capital and achievement of long-term profitability objectives. As EPCOR is wholly-owned by the City, EPCOR does not grant equity securities as compensation to employees or its directors.

2016 MTIP Target Awards

NEOs are eligible for annual target awards under the MTIP, as recommended by the HR&C Committee and approved by the Board. The awards are eligible to vest and become payable at the end of each three-year performance cycle, subject to pro-rated payouts on retirement, death or disability. Pro-rated payouts are based on the number of full months an employee was actively employed by the Corporation during applicable three-year periods.

Target award levels are expressed as a percentage of salary and generally align with the median of the comparator group for positions with similar responsibilities to those of the Corporation's MTIP participants. In 2016, NEO target award levels were 100% for Mr. Lee, 80% for Dr. Bridgeman and 50% for other NEOs. The target award represents the amount that would be paid if the performance objectives were achieved at target.

The plan is funded using a target calculation approach as illustrated below:

Base Salary (e.g. $300,000)	X	MTIP Target Award (e.g. 50%)	X	Actual MTIP Payout % (e.g. 100%)	=	MTIP Award (e.g. $150,000)

2016 MTIP Performance Measures

The performance objectives in respect of 2016 MTIP awards include two equally weighted components, measured over a three year performance period: (a) compounded annual growth rate (CAGR) of Property, Plant & Equipment (PP&E); and (b) Consolidated Net Income in 2018.

The PP&E growth metric is well aligned with the Corporation's primary corporate strategy to place capital and is a leading indicator of future earnings growth. Further, the measure is reasonably stable across most utilities and is easily understood by all participants, facilitating effective line of sight. In addition to tangible assets, PP&E growth calculations incorporate items such as intangible assets, long-term receivables and lease assets that relate to the design, build, finance and operate contracts.

The Consolidated Net Income metric provides focus on increasing the income generated from EPCOR's existing assets and finding significant investment capital to yield long-term earnings growth. For purposes of the MTIP, Consolidated Net Income is normalized to exclude gains and losses related to the investment in Capital Power as explained above, as well as certain unrealized gains and losses related to interest rate swaps and other financial derivatives, and provincial transmission flow-through impacts.

The following table illustrates the performance standards and associated payout levels in respect of 2016 MTIP awards (to be paid out in 2019, if performance warrants). The threshold, target and stretch performance standards were determined in consideration of a number of factors, primarily driven by EPCOR's long-term strategic plan, historical performance among peer companies and defined objectives for capital allocation and net income generation.

Performance Level	**CAGR PP&E (50% Weighting)**	**Consolidated Net Income (50% Weighting)**	**Payout as a % of Target**
Below Threshold	< 6%	< $238 million	0%
Threshold	6%	$238 million	50%
Target	8%	$248 million	100%
Stretch	10%	$258 million	200%

2013 MTIP Awards (paid out in 2016)

Target MTIP awards were provided to eligible NEOs in 2013, with payment made in 2016 based on the Corporation's PP&E growth performance. The strong performance results were driven primarily by organic growth. The table below summarizes actual performance achieved relative to target and the associated payout factor.

	CAGR PP&E (100% weighting)			
	Threshold	**Target**	**Stretch**	**Actual (2013 – 2015)**
Performance	7%	8%	9%	**8.81%**
Payout as a % of Target	50%	100%	200%	**181%**

The value of awards paid to eligible NEOs in respect of 2013 MTIP awards is provided under "Non-Equity Incentive Plan Compensation – Longer-Term Incentive Plans" within the Summary Compensation Table below.

BENEFIT AND PENSION PLANS

The Corporation's benefit and pension plans support the well-being of employees and facilitate retirement savings. The plans are reviewed periodically to determine whether they are competitive and whether they continue to meet the Corporation's business and human resources objectives.

Health and Welfare Benefits

The health and welfare benefit plans are designed to support ongoing wellness, protect the health of employees and their dependents and cover them in the event of death or disability. The executive officers participate in the same benefits program as all other permanent employees of the Corporation. EPCOR provides executives with an annual taxable Executive Benefit Allowance (EBA), paid on a bi-weekly basis, that offsets the costs associated with the benefits and pension plans. The Chief Executive Officer's EBA also covers the cost of completing annual personal income tax filings.

Executive Business Allowance

Executive officers are provided with an annual taxable allowance that can be used to offset the cost of a variety of business related expenses including but not limited to club and business memberships and other out-of-pocket costs associated with performing the duties of the position.

EPCOR Savings Plan

Under the voluntary EPCOR Savings Plan, all Canadian based non-bargaining unit employees may contribute up to 25% of their base salary towards either registered or non-registered accounts with a range of investment options. EPCOR matches employee contributions to a maximum of 5% of base salary.

Defined Benefit Pension Plan

The NEOs participate in the Local Authorities Pension Plan (LAPP), a contributory, defined benefit, highest average earnings pension plan that is currently governed by the *Public Sector Pension Plans Act* (Alberta). The LAPP is a multi-employer pension plan covering approximately 156,141 active employees of Alberta municipalities, hospitals and other public entities as at December 31, 2015.

Supplemental Retirement Plans

EPCOR has two supplemental retirement plans (Supplemental Retirement Plans) that provide benefits that cannot be paid by the LAPP due to the *Income Tax Act* (Canada) limits on earnings.

Effective January 1, 2000, EPCOR adopted a Defined Benefit Supplemental Retirement Plan (DB SRP) for management employees whose earnings exceed the *Income Tax Act* (Canada) limits (base salary plus target short-term incentive). Mr. Lee, Dr. Bridgeman, Mr. Gysel, Dr. Stanley and Mr. Mannarino participate in the DB SRP, which is a non-contributory, defined benefit, best average earnings plan.

As of June 30, 2012, the DB SRP described above was closed to new participants; although Mr. Lee's participation was grandfathered as he was previously an employee of EPCOR as a participant in the plan. Since July 1, 2012, new participants are provided with a Defined Contribution Supplemental Retirement Plan for eligible earnings that exceed the *Income Tax Act* (Canada) limits.

SUMMARY COMPENSATION TABLE

The following table provides a summary of compensation for each of the NEOs in 2016.

			Non-Equity Incentive Plan Compensation				
Name and Principal Position	**Year**	**Salary (1) ($)**	**Annual Incentive Plans (2) ($)**	**Longer-Term Incentive Plans (3) ($)**	**Pension Value (4) ($)**	**All Other Compensation ($)**	**Total Compensation(5) ($)**
Stuart Lee President and Chief Executive Officer	2016 2015	588,462 177,692(6)	620,000 237,416(6)	- -	511,045 851,514	83,525(7) 202,285(8)	1,803,032 1,468,907
Guy Bridgeman Senior Vice President and Chief Financial Officer	2016 2015 2014	365,395 356,904 324,231	263,407 288,649 301,500	317,895 266,975 204,000	246,039 117,393 288,892	60,813(9) 61,682(10) 58,391(11)	1,253,549 1,091,603 1,177,014
Joseph Gysel Senior Vice President, EPCOR Water USA (President, EWUS)	2016(12) 2015 2014	430,091 414,907 355,642	244,292 307,031 286,762	272,159 364,554 342,488	56,856 46,230 83,995	90,994(13) 87,998(14) 74,365(15)	1,094,392 1,220,720 1,143,252
Stephen Stanley Senior Vice President, Commercial Services	2016 2015 2014	307,800 316,800 293,331	124,488 272,688 219,336	187,473 257,925 275,000	139,262 32,781 89,052	61,891(16) 63,095(17) 60,255(18)	820,914 943,289 936,974
Frank Mannarino Senior Vice President, Electricity Services	2016 2015 2014	274,275 293,824 271,778	128,361 202,964 213,935	173,558 140,818 151,200	65,732 67,049 75,811	59,032(19) 61,858(20) 57,860(21)	700,958 766,513 770,584

General Notes:

(1) EPCOR adjusted base salaries effective March 23, 2014, March 22, 2015 and April 2, 2016. Salaries reflect actual amounts earned in 2014, 2015 and 2016 rather than the annualized salaries approved by the Board.
(2) Represents STIP award earned for the stated year's performance and paid in the subsequent year.
(3) Reflects MTIP payments in respect of the three-year performance period ending in the previous year.
(4) This column shows the compensatory value of defined benefit pension entitlements. For the defined benefit plan, the compensatory value equals the supplemental plan employer current service cost, plus any change in the supplemental plan obligation resulting from compensation increases that are different than the actuarial assumptions, plus, if applicable, employer contributions to the LAPP. Actual compensation increases may vary from the actuarial assumptions.
(5) All compensation is reported in Canadian currency. Joseph G. Gysel was paid in U.S. currency with all U.S. dollars paid converted to Canadian currency using the average Canada / U.S. exchange rates as used in preparing the Corporation's consolidated financial statements for the years ended December 31, 2016, 2015 and 2014. The average exchange rate was USD $1 to CDN $1.3256 in 2016, USD $1 to CDN $1.2788 in 2015 and USD $1 to CDN $1.1048 in 2014.

Stuart Lee

(6) Mr. Lee's salary and short-term incentive payment were reflective of his employment from September 1, 2015.
(7) Includes an executive benefit allowance of $24,000, an executive business allowance of $25,000 and a matching contribution under the EPCOR Savings Plan of $29,423.
(8) Includes a one-time signing bonus of $175,000.

Guy Bridgeman *(appointed to CFO position in 2013)*

(9) Includes an executive benefit allowance of $21,500, an executive business allowance of $20,000 and a matching contribution under the EPCOR Savings Plan of $18,270.
(10) Includes an executive benefit allowance of $22,327, an executive business allowance of $20,769 and a matching contribution under the EPCOR Savings Plan of $17,845.
(11) Includes an executive benefit allowance of $21,500, an executive business allowance of $20,000 and a matching contribution under the EPCOR Savings Plan of $16,212.

Joseph Gysel

(12) Mr. Gysel was paid in U.S. currency – the 2016 amounts paid in U.S. dollars were:
Salary - $324,450, Annual Incentive - $184,288, Longer-Term Incentive - $205,310 and Other Compensation - $68,644
(13) Includes an executive benefit allowance of $50,281
(14) Includes an executive benefit allowance of $48,240.
(15) Includes an executive benefit allowance of $39,933.

Stephen Stanley

(16) Includes an executive benefit allowance of $21,500 and an executive business allowance of $20,000.
(17) Includes an executive benefit allowance of $22,327 and an executive business allowance of $20,769.
(18) Includes an executive benefit allowance of $21,500, an executive business allowance of $20,000 and a matching contribution under the EPCOR Savings Plan of $12,467.

Frank Mannarino

(19) Includes an executive benefit allowance of $21,500 and an executive business allowance of $20,000.
(20) Includes an executive benefit allowance of $22,327 and an executive business allowance of $20,769.
(21) Includes an executive benefit allowance of $21,500 and an executive business allowance of $18,654.

Outstanding MTIP Awards

The following table outlines the respective values of outstanding MTIP awards (at target performance levels) granted in 2016, 2015 and 2014 for each NEO.

MTIP Grants (1)	Stuart Lee	Guy Bridgeman	Joseph Gysel(2)	Stephen Stanley	Frank Mannarino
2017 *(payable in 2020)*	$600,000	$296,800	$162,300	$155,700	$137,200
2016 *(payable in 2019)*	$600,000	$296,800	$162,300	$155,700	$137,200
2015 *(payable in 2018)*	$550,000	$260,100	$162,300	$148,200	$137,200

(1) Award amounts are calculated based on each NEOs respective target award as a percentage of salary, and rounded up to the nearest hundred dollars.
(2) Mr. Gysel’s 2014, 2015 and 2016 awards were issued in U.S. dollar amounts and payouts will be converted to Canadian dollar amounts for Summary Compensation Table reporting purposes using Canada / U.S. exchange rates in the years they are paid.

Pension Programs

Benefits payable under the LAPP are based on the average of the highest five consecutive year’s pensionable earnings and years of service. Pensionable earnings are equal to base salary plus paid incentive, up to a maximum of 20% of base salary (effective January 1, 2004). Pensionable earnings are limited for each year of service after 1991 to the earnings, which provide the maximum annual accrual under the *Income Tax Act* (Canada) limits.

Subject to *Income Tax Act* (Canada) limits, the benefit formula under the LAPP is 1.4% of the average of the best five consecutive year’s annual pensionable earnings up to the average Year’s Maximum Pensionable Earnings (YMPE), plus 2% of the average of the best five consecutive year’s annual pensionable earnings in excess of the five year average YMPE under the Canada Pension Plan. The benefit formula is multiplied by years of service.

In 2016, employees were required to contribute 10.39% of pensionable earnings up to the YMPE plus 14.84% of pensionable earnings in excess of the YMPE, and EPCOR contributed 11.39% of pensionable earnings up to the YMPE and 15.84% of pensionable earnings in excess of the YMPE.

Plan members may retire with an unreduced pension if the combination of the individual’s age and years of pensionable service equals at least 85 and they are at least 55 years of age or at age 65. If they choose to take an early retirement, the pension payable under the LAPP is reduced by 3% for each year that the combination of the individual’s age and years of service is less than 85 or for each year the individual is younger than age 65, whichever provides the lesser reduction. No pension is payable if a participant has not completed two years of service.

The pension payable is indexed annually to 60% of the increase in the Alberta consumer price index.

The Supplemental Retirement Plans provide benefits that cannot be paid by the LAPP due to the *Income Tax Act* (Canada) limits on earnings.

- The pensionable earnings defined under the DB SRP include base salary and target short-term incentive (to a maximum of 50%). The benefit formula under the DB SRP is 2% of the average pensionable earnings in excess of the limit on earnings recognized by the LAPP. The benefit formula is multiplied by years of service under the DB SRP commencing no earlier than January 1, 2000. The DB SRP has the same early retirement and indexing provisions as the LAPP.

Pension Plan Table

The following table provides disclosure with respect to the LAPP and EPCOR's DB SRP:

Name	**Number of Years of Credited Service(1) (#)**	**Annual Benefits Payable ($)**		**Opening Present value of defined benefit obligation(8) ($)**	**Compensatory Changes (8, 9) ($)**	**Non-compensatory Changes ($)**	**Closing Present value of defined benefit obligation(8) ($)**
		At Year End(6)	**At age 65(7)**				
(a)	**(b)**	**(c1)**	**(c2)**	**(d)**	**(e)**	**(f)**	**(g)**
Stuart Lee	13.3956(4)	174,080	336,128	2,332,873	511,045	135,509	2,956,373
Guy Bridgeman	27.5696(2)	186,823	245,506	1,762,987	246,039	215,668	2,201,640
Joseph Gysel (10)	7.5000(3)	115,837	166,645	1,394,743	56,856	110,307	1,538,852
Stephen Stanley	17.6612(2)	135,616	219,562	1,278,401	139,262	99,570	1,494,179
Frank Mannarino	6.3169(5)	43,815	143,233	332,622	65,732	38,820	414,120

(1) Credited service in respect of the LAPP as at December 31, 2016.
(2) Credited service under DB SRP is 17 years.
(3) Credited service under DB SRP is 16.3333 years.
(4) Credited service under DB SRP is 13.4370 years.
(5) Credited service under DB SRP is 6.3169 years.
(6) Accrued DB pension under the LAPP and DB SRP as at December 31, 2016 payable at normal retirement age of 65 based on highest average earnings, average YMPE and credited service as at December 31, 2016. An unreduced pension is payable at the earliest of age 65 or 85 points.
(7) Amounts payable on retirement at age 65, assumes continued service accrual to age 65 and that the highest average earnings and estimated average YMPE at age 65, remain unchanged from December 31, 2016.
(8) The defined benefit obligation and service cost for the DB SRP were determined using the same methods and assumptions used to determine accounting information disclosed in EPCOR's financial statements. Accounting entries for the LAPP are recognized on a defined contribution basis; therefore, company contributions to the LAPP are only included in compensatory changes. As a result, columns (d), (e) and (f) do not sum up to column (g).
(9) Includes $23,054 in employer contributions to the LAPP.
(10) There is no currency adjustment for Mr. Gysel.

EMPLOYMENT AGREEMENTS

The Corporation entered into employment-related agreements with Mr. Lee. The Corporation does not have employment-related agreements with the other NEOs.

Stuart Lee

Mr. Lee was appointed President and Chief Executive Officer effective September 1, 2015. Mr. Lee's Executive Employment Agreement is in effect until August 31, 2025. If Mr. Lee was to cease employment with EPCOR, his compensation and benefits would be treated as follows, assuming each event took place on December 31, 2016:

Event	Action	Incremental Payment Resulting from Event
Resignation	• All salary and benefit programs cease. • Annual short-term incentive payment is forfeited. • All mid-term incentives are forfeited. • Vested pension paid as a commuted value.	• No resulting incremental payment.
Death	• All salary and benefit programs cease – survivor health and dental benefits will continue for 24 months. • Annual short-term incentive payment is paid on a pro rata basis coincident with those of active participants. • All unvested mid-term incentives are forfeited. Vested incentives will be paid at target.	• Lump sum payment of approximately $ 1,016,667 minus applicable deductions and withholding taxes.(1)
Termination for Inability to Carry Out Duties(2)	• All salary and benefit programs cease. • Annual short-term incentive payment is paid on a pro rata basis coincident with those of active participants. • All mid-term incentives continue to vest and are settled at the end of the regular performance period. • Following termination, benefits received in accordance with the Corporation's long-term disability plan.	• Long-term disability benefits would continue to be paid by the insurer for the duration of the disability in accordance with plan provisions based on pre-disability coverage (maximum of $20,000 per month).
Termination for cause	• All salary and benefit programs cease. • Annual short-term incentive payment is not paid. • All mid-term incentives are forfeited.	• No resulting incremental payment.
Termination without cause, or Resignation due to a material change to responsibilities within 12 months of the occurrence of a change of control, or Resignation due to a material breach of the employment agreement that the Corporation fails to cure within 120 days following notice	• All salary and benefit programs cease. • Severance is provided representing an aggregate value of 24 months of (i) annual base salary at the rate at the time of termination or resignation, as applicable, (ii) a payment equal to the value of the short-term incentive plan target (i.e. 75% of annual base salary), and (iii) a payment equal to the benefits and pension contributions for a 24 month period. • Mid-term incentives vest for service completed during the applicable performance period and will be paid out at target (i.e. 100% of annual base salary).	• Lump sum severance payment of approximately $2.3 million minus applicable deductions and withholding taxes; plus • Lump sum mid-term incentive payment of approximately $0.6 million minus applicable deductions and withholding taxes.(1)

(1) Represents an estimate of the value only based upon the information available as at December 31, 2016. This amount is subject to change and should not be relied upon as a statement of final value.
(2) Mr. Lee's employment can be immediately terminated by providing 30 days' notice if he is unable to perform his employment-related duties due to incapacity for a period of six consecutive months as his continued employment would constitute undue hardship for the Corporation.

BOARD OF DIRECTORS COMPENSATION

The directors' compensation program is designed to attract and retain the most qualified individuals to serve on the Board. The program takes into account the time commitment, duties and responsibilities of the directors, and the director compensation practices at comparable companies.

The program is reviewed periodically to ensure it remains competitive. Director compensation is benchmarked against publicly traded companies in the comparator group used to determine competitive compensation for the Corporation's executives. The last review was conducted in 2010 and revealed that the Corporation's director compensation was positioned at the median of the market.

In consideration for serving on the Board for 2016, directors were compensated as indicated below:

Type of Fee	Amount ($)(6)
Board Chair Annual Retainer	150,000(1)
Director Annual Retainer	30,000(2)
Director Annual Stock Retainer	30,000(3)
Travel Related Compensation	500(4)
Audit Committee Chair Annual Retainer	9,000
Audit Committee Member Annual Retainer	6,000
Other Committee Member Annual Retainer	3,000
Board Meeting Attendance Fee	1,500
Audit Committee Meeting Attendance Fee	3,000
Other Committee Meeting Attendance Fee	1,500
Annual General Meeting Attendance Fee	1,500
Shareholder Meeting Attendance Fee(5)	1,500

(1) The Chair of the Board receives an annual retainer of $150,000, paid in quarterly installments of $37,500.
(2) Of the annual retainer fee paid to each Director, except the Chair, $1,500 is subject to directors exercising their right to further education related to fulfilling their Board responsibilities and / or educating the Director on strategic and business processes relevant to the Corporation's business and governance issues.
(3) Each Director, including the Chair, is paid an annual $30,000 in lieu of stock-based compensation commonly paid to directors by EPCOR's publicly traded comparators, as the option to purchase shares in EPCOR is not available.
(4) In circumstances in which a Director must travel from his or her place of residence the day before a board or committee meeting and/or travel back to their residence the day following a meeting, the Director is entitled to a travel allowance equal to $500 per instance.
(5) The Chair of the Board is paid a $1,500 meeting fee to attend Shareholder meetings. Directors whose attendance is requested by the Board Chair or Management are also paid a $1,500 meeting fee.
(6) Directors who are resident in the United States are compensated in U.S. dollars at the figures noted above. For example, a U.S. resident director is paid USD $30,000 in respect of the Director Annual Retainer, $1,500 of which is subject to the director exercising their right to education. Currently, Mr. Foster is the only U.S. resident director and is compensated in U.S. dollars; for a summary of his actual 2016 compensation in Canadian dollars, please see the Director Compensation Table below.

The directors are reimbursed for out-of-pocket expenses incurred in carrying out their duties as directors of the Corporation.

The table below reflects in detail the compensation earned by directors with respect to the calendar year-ended December 31, 2016:

Director Compensation Table

Name	Fees Earned ($)	Share-Based Awards ($)	Option-Based Awards ($)	Non-Equity Incentive Plan Compensation ($)	Pension Value ($)	All Other Compensation (1) ($)	Total ($)
Hugh J. Bolton	226,500	-	-	-	-	9,750	236,250
Vito Culmone	103,000	-	-	-	-	3,600	106,600
Robert G. Foster(2)	126,578	-	-	-	-	-	126,578
Allister J. McPherson	97,500	-	-	-	-	-	97,500
Douglas H. Mitchell	88,000	-	-	-	-	-	88,000
Laurence M. Pollock(3)	31,000	-	-	-	-	-	31,000
Catherine M. Roozen	101,000	-	-	-	-	-	101,000
Helen K. Sinclair	100,500	-	-	-	-	3,375	103,875
Nizar Jaffer. Somji	103,750	-	-	-	-	3,663	107,413
Sheila C. Weatherill	92,000	-	-	-	-	3,075	95,075

(1) Represents amounts contributed by EPCOR under the voluntary Employee Savings Plan, where EPCOR matches contributions to a maximum of 5% of the director's contribution.

(2) Mr. Foster is a U.S. resident and all compensation was converted to U.S. dollars using exchange rates at dates of payment.
(3) Mr. Pollock retired in May 2016.

FORWARD-LOOKING INFORMATION

Certain information in this AIF is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target”, “could” and “expect” or similar words suggest future outcomes. The purpose of forward-looking information is to provide investors with management’s assessment of future plans and possible outcomes and may not be appropriate for other purposes. Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. All forward-looking information contained in this AIF is expressly qualified by this cautionary statement.

Forward-looking information in this AIF includes, or is related to, but is not limited to: (i) expectations related to customer growth; (ii) the expected terms of the Evan-Thomas and Regina agreements; (iii) expectations related to the renewal of the Corporation’s water, wastewater and electricity distribution franchise agreements with the City; (iv) expected expiration of water supply agreements in 2018 and 2023; (v) expectations related to projected capital expenditures and construction projects; (vi) expectations related to the cap on RRO customer rates and customer attrition; (vii) competition; and (viii) credit rating expectations.

The forward-looking information in this AIF involves numerous assumptions, inherent risks and uncertainties, including but not limited to the following factors: (i) the Corporation’s assessment of the economy, markets, government and regulatory environments in which it operates; (ii) availability and cost of financing; (iii) availability and cost of labor and management resources; (iv) performance of counterparties, including but not limited to contractors and suppliers, in fulfilling their obligations to the Corporation; (v) the Corporation’s ability to secure new utility investments; and (vi) quality and sufficiency of water supply. There are more specific factors that could cause actual results to differ materially from those described in this AIF. The more specific factors and related assumptions are identified and discussed in the sections entitled “Forward-Looking Information” and “Risk Factors and Risk Management” in the Corporation’s MD&A dated March 2, 2017 for the year ended December 31, 2016.

Except as required by law, EPCOR disclaims any intention and assumes no obligation to update any forward-looking statement, even if new information becomes available as a result of future events or for any other reason.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com and on the Corporation’s website at www.epcor.com.

Additional financial information is provided in the Corporation’s audited consolidated financial statements and MD&A for the year ended December 31, 2016.

APPENDIX I

AUDIT COMMITTEE
TERMS OF REFERENCE

A. OVERVIEW AND PURPOSE

1. The Audit Committee (the "Committee"), except to the extent otherwise provided by law, is responsible to the Board of Directors (the "Board"). The Committee monitors, evaluates, advises or makes recommendations, in accordance with these Terms of Reference and any other directions of the Board, on matters affecting the financial and operational control policies and practices relating to the Corporation, including the external, internal or special audits thereof. The term "Corporation" when used within these Terms of Reference includes all corporations and other entities within the EPCOR group of companies.

2. Management is responsible for preparing the interim and annual financial statements of the Corporation and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly.

3. The Committee is responsible for reviewing management's actions and has the authority to investigate any activity of the Corporation. The primary responsibilities of the Committee include:

   - Assessing the processes related to identification of the Corporation's financial risks and effectiveness of its control environment;
   - Overseeing financial reporting;
   - Evaluating the Corporation's internal control systems for financial reporting; and
   - Evaluating the internal and external, and any special, audit processes.

4. The Committee shall have unrestricted access to company personnel and documents, including internal auditors, and will be provided with the resources necessary to carry out its responsibilities. Neither the Chief Financial Officer nor the Director, Risk Assurance & Advisory Services will be disciplined, demoted or terminated without the prior knowledge of the Committee and the Committee will be consulted prior to any decisions by Management regarding hiring for either of these roles. The Committee has the authority to retain, at the expense of the Corporation, outside advisors and consultants as it sees fit.

5. The Committee shall be the direct report for the external auditors, shall evaluate their performance and shall recommend their compensation to the Board.

B. STRUCTURE

1. The Committee shall be composed of such number of directors as may be specified by the Board from time to time, which number shall be not less than three.

2. The Chair of the Board is an ex officio and non-voting member of the Committee, unless appointed by the Board as a member of the Committee.

3. At the first meeting of the Board following the Annual General Meeting with the Shareholder, Committee members and the Committee Chair are appointed by the Board on the recommendation of

the Chair of the Board, to hold office until such time as new Committee members and a new Committee Chair are appointed.

4. Each Committee member should be independent and unrelated, as set forth in applicable securities laws, rules or guidelines of any stock exchange on which the securities of the Corporation are listed for trading, (which shall include, without limitation, National Instrument 52-110 issued by the Canadian Securities Administrators, or its successor instrument), and have no relationship to the Corporation that may materially interfere with the member's ability to act with a view to the best interests of the Corporation.

5. All Committee members shall possess sufficient financial literacy (as that term is defined in National Instrument 52-110 issued by the Canadian Securities Administrators, or its successor instrument) to effectively discharge their responsibilities. At least one member of the Committee shall have a professional accounting designation or equivalent financial expertise as determined by the Board.

6. All members of the Board shall be free to attend any meetings of the Committee and participate, but only Committee members shall be entitled to vote on any question before the Committee. Other than members of the Board, entitlement to attend all or a portion of any Committee meeting shall be determined by the Committee Chair or the Committee members.

7. The Committee shall meet at least four times per year and may call other meetings as required.

8. The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee members and others as directed by the Committee.

C. DUTIES AND RESPONSIBILITIES

In respect of all financial matters, the Committee is responsible for:

Public Disclosure of Financial Information

1. establishing and reviewing procedures for the review of all public disclosure documents containing audited, unaudited or forward-looking financial information before release by the Corporation including reviewing and recommending to the Board any changes to the Disclosure and Insider Trading Policy;

2. reviewing public documents containing financial information (annual audited financial statements, quarterly interim financial statements, annual and quarterly management discussion and analysis, media releases, the Annual Information Form, and any Prospectus or offering memorandum) before such documents are submitted to the Board of Directors (“Board”) for approval, and making recommendations as to their approval by the Board;

3. reviewing the annual and interim certificates provided by the Chief Executive Officer and Chief Financial Officer of the Corporation pursuant to National Instrument 52-109 issued by the Canadian Securities Administrators;

4. obtaining and reviewing reports from management and the external auditors describing the critical accounting policies used by the Corporation in the preparation of its annual and interim financial statements; any alternative treatments of financial information within generally accepted accounting principles (“GAAP”) that have been evaluated; and any other material written communications;

5. reviewing accruals, reserves and estimates which have a material effect on financial results;

6. reviewing the use of any “pro forma” information or “adjusted” information not in accordance with GAAP or use of any special purpose vehicles and / or off-balance sheet transactions;

7. reviewing with management and the external auditors, a summary of information in respect of the Ethics Policy and any litigation, claim or other contingency that could have a material effect upon the financial position or operating results of the Corporation, and the manner in which these will be disclosed in the financial statements;

8. monitoring compliance with the Corporation's Ethics Policy and ensuring that Management Compliance Certificates are received from management quarterly;

9. reviewing responses of management to information requests from government or regulatory authorities in respect of filing documents required under securities legislation, which may affect the financial reporting of the Corporation;

Internal Controls Over Financial Reporting

10. monitoring the appropriateness of accounting policies and financial reporting used by the Corporation, reviewing any prospective changes in financial reporting and accounting policies that may affect the Corporation;

11. obtaining reasonable assurance from discussions with and reports from the internal auditors and management that the Corporation's accounting systems are reliable and that the prescribed internal controls are operating effectively;

12. reviewing whether management has implemented policies ensuring that the Corporation's financial risks are identified and that controls are adequate, in place and functioning properly;

13. reviewing the post-audit management letter together with management's responses to external auditor recommendations together with status reports relating to follow-up actions;

14. reviewing all follow-up actions or status reports relating to the recommendations of the internal auditor;

15. reviewing the management prepared tax compliance and planning strategies annually, including a review of any tax exposures;

16. receiving and reviewing reports of all allegations related to financial impropriety and / or fraud, ensuring the investigations were conducted on a basis that protects the confidentiality of the complainer;

Financial Management

17. reviewing management's plans and strategies around investment practices, banking performance and treasury risk management;

18. reviewing and recommending to the Board any new or renewed financings including commercial paper programs, credit facilities, debt financings and equity financings;

19. reviewing management's procedures to ensure compliance by the Corporation with its loan and indenture covenants and restrictions, if any;

20. reviewing management’s plans, strategies and insurance coverage;

21. obtaining such information and explanations regarding the accounts of the Corporation as the Committee may consider necessary and appropriate to carry out its duties and responsibilities;

External Auditor Oversight

22. reviewing management’s assessment and completing the Committee’s assessment of external auditor performance, including an assessment of the objectivity and independence of the external auditor and obtaining written confirmation from the external auditor;

23. reviewing reports from external auditors respecting their internal quality control procedures and regulatory inspections;

24. recommending to the Board the appointment or the removal of external auditors, for approval by the Shareholder;

25. recommending to the Board for approval, the compensation paid to the external auditors on an annual basis;

26. approving the scope of the audit, including materiality, audit reports required, areas of audit risk, timetable and deadlines, including approving the auditor's engagement letters;

27. pre-approving all non-auditing services performed by the external auditors in relation to the Corporation and its subsidiaries;

28. meeting with the external auditors each quarter and when requested by the auditors, without management representatives present;

29. reviewing any other matters the external auditors bring to the attention of the committee;

30. confirming that appropriate liaison and cooperation exists where necessary between the external auditors and the internal auditors, and to provide a direct line of communication between the auditors and the Committee;

31. resolving issues with management regarding financial reporting;

32. reviewing and approving hiring policies regarding employees and former employees of the present and former external auditors;

Internal Auditor Governance

33. reviewing and approving the annual internal audit plan, including the mandate, staffing, scope and objectives of the internal audit department, and receiving regular reports on internal audit results and access to all internal audit reports, including status of all audit findings;

34. annually reviewing the budget of the internal audit function and directing the Chief Financial Officer to make any changes necessary;

35. annually reviewing the performance and independence of the internal audit function and directing the Chief Financial Officer to make any changes necessary;

36. meeting with the internal auditors each quarter or as requested by the auditors, without management representatives present;

Audit Committee Governance

37. reviewing annually the Terms of Reference for the Committee and recommending any required changes to the Board;

38. conducting periodic self-assessment relating to Committee effectiveness and performance;

39. conducting all other matters required by law or stock exchange rules to be dealt with by an audit committee;

40. reporting to the Board as required.

D. MEETINGS

1. Committee meetings may be called by the Committee Chair or by a majority of the Committee members. In addition, the Committee Chair shall call a meeting upon request of the external auditors.

A majority of Committee members shall constitute a quorum. The Committee Chair shall be a voting member and questions will be decided by a majority of votes.

2. Meetings may be called with one day's notice, which may be waived by Committee members. Attendance at a meeting shall be deemed to be waiver of notice of the meeting except where the Committee member attends the meeting for the express purpose of objecting to the transaction of business on the grounds that the meeting has not been duly called. All Committee members are entitled to receive notice of every meeting.

3. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a Committee member chosen from amongst and by the Committee members present at the meeting.

4. Agendas will be set by the Committee Chair with such assistance as the Committee Chair may request from the Chief Executive Officer, the Chief Financial Officer, the General Counsel and the auditors, and will be circulated with the materials for consideration at the meeting by the Assistant Corporate Secretary to all Committee members, the Chair of the Board, the Chief Executive Officer, the Chief Financial Officer and the General Counsel, no later than the day prior to the date of the meeting. However, it should be standard practice to deliver the agenda and the materials for consideration at the meeting at least five business days prior to the proposed meeting except in unusual circumstances.

5. Except as herein provided, the Committee Chair may establish rules of procedure to be followed at meetings.

6. Meetings may be conducted with the participation of one or more of the Committee members by telephone which permits all persons participating in the meeting to hear and communicate with each other. A Committee member participating in a meeting by telephonic means is deemed to be present at the meeting.

7. The powers of the Committee may be exercised at a meeting at which a majority of the Committee members are present, or by resolution in writing signed by all Committee members who would have been entitled to vote on the resolution at a meeting of the Committee.

8. A resolution in writing may be signed and executed in separate counterparts by Committee members and the signing or execution of a counterpart shall have the same effect as the signing or execution of the original. An executed copy of a resolution in writing or counterpart thereof transmitted by any means of recorded electronic transmission shall be valid and sufficient.

9. Attendance at all or a portion of Committee meetings by staff will be determined by the Committee and will normally include the Chief Executive Officer, the Chief Financial Officer and the General Counsel.

10. The Corporate Secretary shall keep minutes of the proceedings of all meetings of the Committee, which following Committee approval are available to any member of the Board. All minutes will be circulated to the Chair of the Board and to those receiving the agenda, and will be retained by the Assistant Corporate Secretary.

11. The Committee may delegate its power and authority to individual members of the Committee, where the Committee determines it is appropriate to do so in order for necessary decisions to be made between meetings of the Committee and where such delegation is permitted by law. Any such decisions shall be reported to the Committee at its next meeting.

APPENDIX II

CHARTER OF EXPECTATIONS
FOR THE BOARD OF DIRECTORS

I. INTRODUCTION

A. The Directors have the power to manage the business and affairs of the Corporation except as limited or restricted by the Unanimous Shareholder Agreement, the Act, the Articles, and the By-laws.

B. EPCOR has adopted a Charter of Expectations for the Board of Directors, which sets out the specific responsibilities to be discharged by EPCOR's Board. The purpose of the Charter is to assist the Board in annually assessing its performance.

C. While the Board is called upon to "manage" the business by law, this is done by proxy through the President and Chief Executive Officer (CEO) who is charged with the day-to-day leadership and management of the Corporation. The President / Chief Executive Officer's prime responsibility is to lead the Corporation. The CEO formulates strategies and plans and presents them to the Board for approval. The Board approves the goals of the business, the objectives and policies within which it is managed, and then steps back and evaluates management performance. Reciprocally, the CEO keeps the Board fully informed of the Corporation's progress towards the achievement of its goals and of all material deviations from the goals or objectives and policies established by the Board in a timely and candid manner.

II. RESPONSIBILITIES

All of the following responsibilities are undertaken within the parameters and restrictions established by the Unanimous Shareholder Agreement, the Act, the Articles, and the By-laws.

A. Managing the Affairs of the Board

The Board manages the affairs of the Board by establishing committees to provide more detailed review of important areas of responsibility, delegating certain of its authorities to management, reserving certain powers to itself and making certain recommendations to the Shareholder. These include:

(i) appointing committees and / or advisory bodies and establishing and periodically reviewing their terms of reference;

(ii) implementing processes to evaluate the performance of the Board, Committees and Directors in fulfilling their responsibilities;

(iii) implementing processes for new Director orientation and ongoing Director development;

(iv) appointing the Vice–Chair, and the Secretary;

(v) establishing and enforcing a Board confidentiality policy;

(vi) implementing effective governance processes to fulfill its responsibility for oversight and control; and

(vii) making recommendations to the Shareholder in the following areas:

(a) director compensation;

(b) the procedure for the appointment of the Board Chair and the Directors; and

(c) suggested changes for the Shareholder to consider regarding the By-law, Articles and Shareholder Agreement;

B. Strategy and Plans

The Board has the responsibility to:

(i) participate with management in the Corporation's strategic planning process including;

(a) providing input to management on emerging trends and issues;

(b) reviewing and approving management's strategic plans (long-term business plan); and

(c) reviewing and approving EPCOR's financial objectives, plans and actions, including significant capital allocations and expenditures;

(ii) approve annual capital and operating budgets which support the Corporation's ability to meet the objectives established in the strategic plan;

(iii) approve the organization of business units and subsidiaries as outlined in By-law Number 1 (Part II, 2.9); and

(iv) monitor the Corporation's progress towards its goals, and to revise and alter its direction through management in light of changing circumstances.

C. Management and Human Resources

The Board has the responsibility for:

(i) the appointment, termination and succession of the President / Chief Executive Officer (CEO);

(ii) approving CEO compensation;

(iii) approving terms of reference for the CEO;

(iv) monitoring CEO performance and reviewing CEO performance at least annually, against agreed upon written objectives;

(v) providing advice and counsel to the CEO in the execution of the CEO's duties;

(vi) approving decisions relating to senior management, including the:

(a) appointment and discharge of officers;

(b) compensation and benefits for officers;

(c) acceptance of outside directorships on public companies by officers (other than not-for-profit organizations);

(vii) ensuring succession planning programs are in place, including programs to train and develop management;

(viii) approving certain matters relating to all employees, including:

(a) the annual compensation policy / program for employees;

(b) new benefit programs or material changes to existing programs;

(c) material benefits granted to retiring employees outside of benefits received under approved pension and other benefit programs; and

(ix) approving the parameters for negotiated union collective agreements with employees of the Corporation.

D. Business and Risk Management

The Board has the responsibility to:

(i) monitor corporate performance against the strategic, operating and capital plans, including assessing operating results to evaluate whether the business is being properly managed and meeting its objectives;

(ii) ensure management identifies the principal risks of the Corporation's business and implements appropriate systems to manage these risks;

(iii) receive, at least annually, reports from management on matters relating to, among others, ethical conduct, environmental management, employee health and safety, human rights, and related party transactions;

(iv) assess and monitor management control systems:

(a) evaluate and assess information provided by management and others (e.g. internal and external auditors) about the effectiveness of management control systems; and

(b) understand principal risks and determine whether the Corporation achieves a proper balance between risk and returns, and that management ensures that systems are in place to address the risks identified.

E. Financial and Corporate Issues

The Board has the responsibility to:

(i) take reasonable steps to ensure the implementation and integrity of the Corporation's internal control and management information systems;

(ii) meet regularly with and receive reports from the Auditor;

(iii) monitor operational and financial results;

(iv) approve annual and quarterly financial statements, and approve release thereof by management;

(v) declare dividends subject to the dividend policy established by the Shareholder;

(vi) approve significant debt financing, banking resolutions, significant changes in banking relationships and exercise the borrowing powers outlined in By-Law Number 1 (Part II, 2.7);

(vii) review coverage, deductibles and key issues regarding corporate insurance policies;

(viii) approve commitments that may have a material impact on the Corporation;

(ix) approve the commencement or settlement of litigation that may have a material impact on the Corporation; and

(x) recommend, as required, to the Shareholder for approval;

(a) the appointment of external auditors and the auditors' fees;

(b) a dividend policy; and

(c) the merger, amalgamation, acquisition, lease or disposition of assets as outlined in the Unanimous Shareholder Agreement Sections 2.2.10 through and including 2.2.14.

F. Shareholder and Corporate Communications

The Board has the responsibility to take all reasonable steps to:

(i) ensure the Corporation has in place effective communication processes with the Shareholder and other stakeholders and financial, regulatory and other recipients;

(ii) ensure that the financial performance of the Corporation is adequately reported to the Shareholder, other security holders and regulators on a timely and regular basis;

(iii) ensure the financial results are reported fairly and in accordance with generally accepted accounting principles;

(iv) ensure the timely reporting of any other developments that have a significant and material impact on the value of the Corporation;

and the responsibility to:

(v) report quarterly and annually to the Shareholder as outlined in By-Law Number 1 (Part VIII, 8.2 and 8.7).

(vi) organize an annual planning meeting with the Shareholder and place before the Shareholder those items outlined in By Law Number 1 (Part VIII, 8.5).

G. Policies and Procedures

The Board has the responsibility to take all reasonable steps to:

(i) approve and monitor compliance with all significant policies and procedures by which the Corporation is operated;

(ii) direct management to ensure the Corporation operates at all times within applicable laws and regulations and to the highest ethical and moral standards; and

(iii) review significant new corporate policies or material amendments to existing policies (including, for example, policies regarding business conduct, conflict of interest and the environment).

III. GENERAL LEGAL OBLIGATIONS OF THE BOARD OF DIRECTORS

A. The Board is responsible for directing management to ensure legal requirements have been met, and documents and records have been properly prepared, approved and maintained.

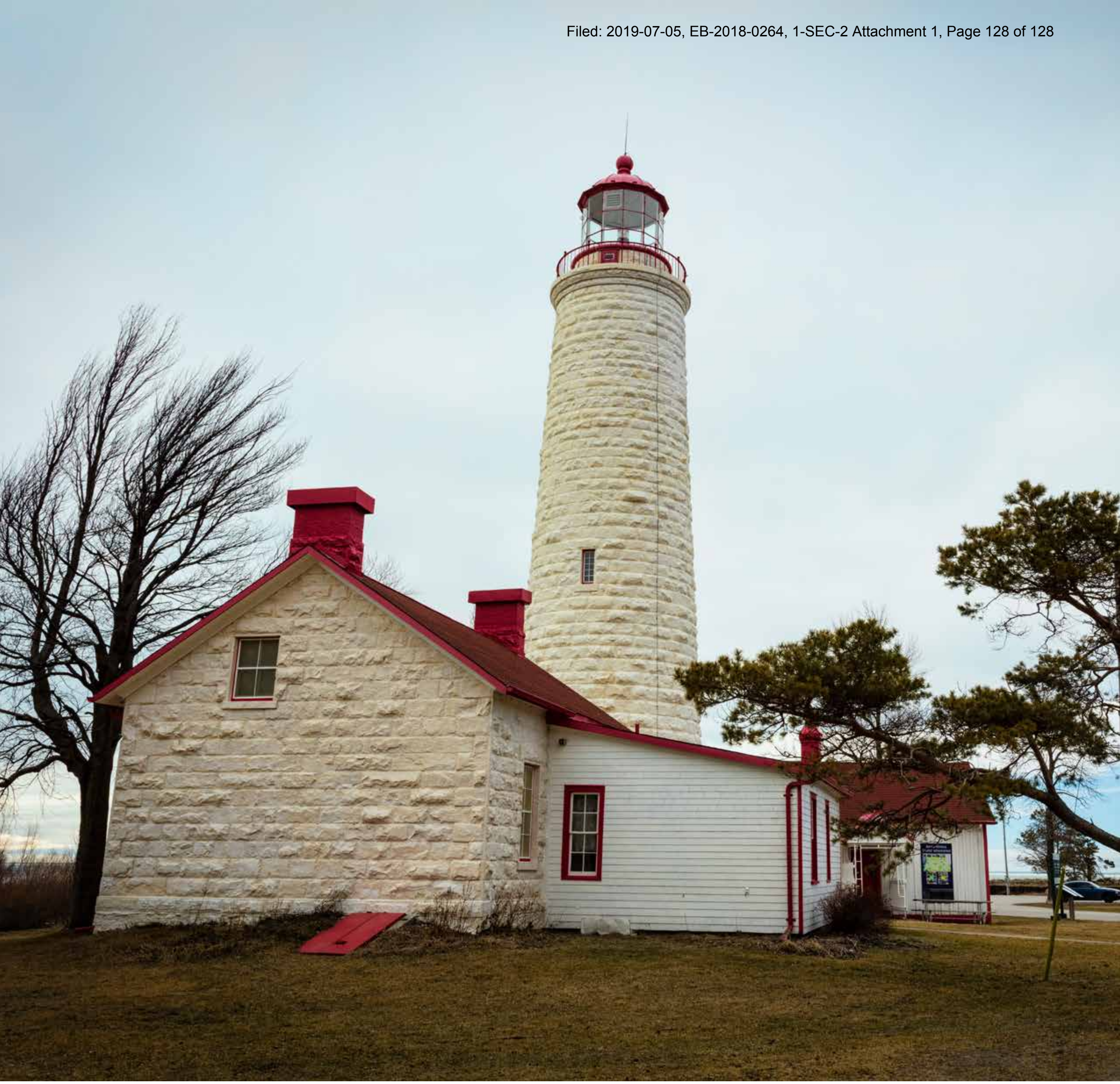
B. Alberta law includes the following as legal requirements for Directors:

(i) to manage the business and affairs of the Corporation subject to any Unanimous Shareholder Agreement;

(ii) to act honestly and in good faith with a view to the best interests of the Corporation;

(iii) to exercise the care, diligence and skill that reasonably prudent people would exercise in comparable situation; and

(iv) to act in accordance with the obligations contained in the Act, the Unanimous Shareholder Agreement and any other relevant legislation, regulations and policies, and the Corporation's Articles and By-laws.



Submitted by
EPCOR Southern Bruce Gas Inc.
c/o EPCOR Commercial Services Inc.
2000 – 10423 – 101 Street NW
Edmonton, AB T5H 0E8

1-SEC-3

Reference: Exhibit 1-2-1, p.31

Questions:

Are there any other items that were excluded from the CIP revenue requirements that will result in either higher or lower actual costs to EPCOR that it has not included? If so, please provide a list, there impact, and the reasons for why it has not included them in its proposed revenue requirement.

Responses:

Items not included in the reference above have been detailed below.

Table 1-SEC-3-1

Other Items Excluded from CIP Revenue Requirements

		Col. 1
	Items not included in gross Revenue Requirement	Impact on revenue requirement
Row 1	Demand-side management costs – Not included at direction of OEB	• EPCOR is not proposing a DSM program
Row 2	Cap and Trade Costs – Not included at direction of OEB.	• Program replaced with Federal Carbon Tax. See 4-SEC-12 for impact on revenue requirement
Row 3	Other Revenue	• Offset impact unknown at this time, but expected to be minimal for initial 3 years of operation. See Exhibit 3.3 paragraph 3 for EPCOR's proposal for addressing Other Revenue

1-SEC-4

Reference: Exhibit 1-2-1, p.32

Questions: Please provide a revised version of Table 1-5 showing EPCOR's most recent customer growth forecasts.

Responses:

As per the Board's decision on the Southern Bruce competitive process, "the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal"[1]. As a result, EPCOR has filed customer growth forecasts that are consistent with its CIP. These customer growth forecasts are the basis for the rates which have been proposed in the application and have not been updated.

[1] EB-2016-0137/0138/0139 Decision and Order South Bruce Expansion Applications, April 12, 2018, Section 4.2, page 11

1-SEC-5

Reference: Exhibit 1

Questions: With the exception of property taxes, is EPCOR paying any fee or other charges to any of the Southern Bruce Municipalities? If so, please provide details. Please also indicate if that amount is included the proposed revenue requirement.

Responses:

Other than normal course fees or charges associated with construction and operations of a utility, EPCOR is not paying any other fee or charge to the Southern Bruce Municipalities. The proposed revenue requirement includes any fee or charge that EPCOR is currently aware of.

2-SEC-6

Reference: Exhibit 2

Preamble: *SEC seeks to understand the difference between the CIP and EPCOR's actual expected plans.*

Questions:

(a) Please explain all the differences between the assumptions in the CIP and EPCOR's actual proposed plan that do not relate to the timing differences outlined in Exhibit 6.

(b) Please provide a table that compares the revenue requirement by year proposed as part of the CIP, as well as what EPCOR actually expects to occur on its most recent information. Please breakdown the reasons for the variances.

(c) Please provide a table that compares the customer growth forecast and volume forecasts it filed with its CIP proposal and any revised customer forecast estimates, that that were caused of or by, a differences between EPCOR's current proposed plan and the CIP, excluding timing issues outlined in Exhibit 6.

Responses:

(a) As per the Board's decision on the Southern Bruce competitive process "the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal"[1]. As a result, EPCOR has filed an application that is consistent with its CIP for which the Board has determined it is responsible. These assumptions have not been updated.

(b) Please see (a) above.

(c) Please see (a) above.

[1] EB-2016-0137/0138/0139 Decision and Order South Bruce Expansion Applications, April 12, 2018, Section 4.2, page 11

3-SEC-7

Reference: Exhibit 3

Questions: Please provide the status of external funding. Please provide all terms and agreements that EPCOR has entered into regarding any sources of external funding.

Responses:

Further to Ontario Regulation 24/19: Expansion of Natural Gas Distribution Systems, the Southern Bruce project is eligible for up to $22.0 million in funding. EPCOR has not entered into any agreements regarding this funding. EPCOR is expecting a draft agreement related to this funding from the IESO in due course.

4-SEC-8

Reference: Exhibit 4-1-1, p.19

Questions: Has EPCOR entered into any shared service agreements regarding the sharing of services with any EUI affiliate? If so, please provide a copy. If there is no agreement, please provide a copy of EPCOR's or any of its affiliates (which would share serves with it) shared services policy or similar document.

Responses:

EPCOR Southern Bruce has not yet entered into Service Level Agreements (SLA) with its affiliates. See Exhibit 4, Tab 2, Schedule 1 for a copy of the SLA template which will be used by EPCOR for these agreements.

4-SEC-9

Reference: Exhibit 4

Questions: EPCOR has provided a number of tables breaking down its OM&A costs. Are those tables a reflection of:

a) EPCOR's actual forecast costs when the application was filed,

b) a breakdown of the actual underlying costs that were forecasted in its CIP proposal ,

c) after the fact allocation of the cost that made up its CIP proposal, or

d) other (if so please explain)?

Responses:

These tables are a breakdown of the forecast underlying costs that were forecasted in EPCOR's CIP.

4-SEC-10

Reference: Exhibit 4-1-1, p.24

Preamble: *EPCOR states that for service allocated by composite cost allocator, it is done based on "factors in business unit's share of EUI's total revenue, assets and headcount".*

Questions: Please provide further details including the actual allocation factors used for each of the listed departments and headcount that is allocated on a composite basis.

Responses:

See the tables below. Table 4-SEC-10-1 provides a detailed breakdown of the allocators used for each of the departments providing EUI Corporate Shared Services to EPCOR Southern Bruce. Table 4-SEC-10 – 2 provides a breakdown of the actual allocation factors and percentages.

Table 4-SEC-10– 1
EUI's Allocators to EPCOR Southern Bruce

	Department and Function	A Allocators
	Supply Chain Management	
1	Mailroom	Functional Cost Causation - Canadian Headcount
2	Disaster Recovery Planning	Functional Cost Causation - Canadian Direct IS Costs
3	Procurement	Functional Cost Causation - Purchase Order Lines
4	Real Estate	Composite - EUI Revenue, Assets, Headcount
5	Security	Functional Cost Causation - Canadian 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 - Canadian 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

Table 4-SEC-10– 2
EUI Corporate Shared Services Allocators and Percentages for 2020

		A **EPCOR Southern Bruce**	B **Other**	C **Canada Total**	D **EPCOR USA**	E **Total**
	Functional Cost Causation Allocators					
1	Headcount	7	3,117	3,124	316	3,440
2	CAD Headcount percentage	0.2%	99.8%	100.0%	0.0%	100.0%
3	Headcount percentage	0.2%	90.6%	90.8%	9.2%	100.0%
4	Assets	55.72	9,664.09	9,719.81	1,320.19	11,040.01
5	Assets percentage	0.5%	87.5%	88.0%	12.0%	100.0%
6	PP&E	50.41	8,995.81	9,046.22	1,264.52	10,310.74
7	PP&E percentage	0.5%	87.2%	87.7%	12.3%	100.0%
8	CapEx	0.16	636.76	636.92	100.58	737.50
9	CapEx percentage	0.0%	86.3%	86.4%	13.6%	100.0%
10	Debt	36.31	3,156.13	3,192.44	636.67	3,829.11
11	Debt percentage	0.9%	82.4%	83.4%	16.6%	100.0%
12	Revenues	8.73	1,896.97	1,905.70	239.95	2,145.65
13	Revenues percentage	0.4%	88.4%	88.8%	11.2%	100.0%
14	Depreciation	1.16	257.11	258.27	53.76	312.03
15	Depreciation Percentage	0.4%	82.4%	82.8%	17.2%	100.0%
16	Net Income	2.57	199.26	201.83	19.33	221.16
17	Net Income Percentage	1.2%	90.1%	91.3%	8.7%	100.0%
18	Direct IS	0.03	8.13	8.16	1.96	10.12
19	CAD Direct IS percentage	0.4%	99.6%	100.0%	0.0%	100.0%
20	Direct IS percentage	0.3%	80.3%	80.7%	19.3%	100.0%
21	Invoice Lines	3,051	433,370	436,421	0	436,421
22	Invoice Lines percentage	0.7%	99.3%	100.0%	0.0%	100.0%
23	PO Lines	49	29,962	30,011	0	30,011
24	PO Lines percentage	0.2%	99.8%	100.0%	0.0%	100.0%
25	Acquisitions	0	6	6	5	11
26	Acquisitions percentage	0.0%	54.5%	54.5%	45.5%	100.0%
27	**Treasurer - Corporate Finance Allocator**					
28	PP&E %	0.5%	87.2%	87.7%	12.3%	100.0%
29	Calculation Weighting %	40.0%	40.0%	40.0%	40.0%	40.0%

30	**Weighting - PP&E**	**0.2%**	**34.9%**	**35.1%**	**4.9%**	**40.0%**
31	CapEx %	0.0%	86.3%	86.4%	13.6%	100.0%
32	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%
33	**Weighting - Cap Ex**	**0.0%**	**25.9%**	**25.9%**	**4.1%**	**30.0%**
34	Acquisitions %	0.0%	54.5%	54.5%	45.5%	100.0%
35	Calculation Weighting %	30.0%	30.0%	30.0%	30.0%	30.0%
36	**Weighting - Acquisitions**	**0.0%**	**16.4%**	**16.4%**	**13.6%**	**30.0%**
37	**Total - All Weightings - Treasurer Corporate Finance Allocation**	**0.2%**	**77.2%**	**77.4%**	**22.6%**	**100.0%**
38	**Treasury Operations - Allocator**					
39	Weighting - Net Income + Depreciation	0.8%	86.2%	87.0%	13.0%	100.0%
40	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%
41	**Weighting - Net Inc + Depn**	**0.4%**	**43.1%**	**43.5%**	**6.5%**	**50.0%**
42	Debt %	0.9%	82.4%	83.4%	16.6%	100.0%
43	Calculation Weighting %	50.0%	50.0%	50.0%	50.0%	50.0%
44	**Weighting - Debt**	**0.5%**	**41.2%**	**41.7%**	**8.3%**	**50.0%**
45	**Total - NI & Depn + Debt - Treasury Operations Allocation**	**0.9%**	**84.3%**	**85.2%**	**14.8%**	**100.0%**
46	**2020F Composite Cost Causation Allocator**					
47	Revenues	0.4%	88.4%	88.8%	11.2%	100.0%
48	Assets	0.5%	87.5%	88.0%	12.0%	100.0%
49	Headcount	0.2%	90.6%	90.8%	9.2%	100.0%
50	**Average - Composite Cost Causation Allocator**	**0.4%**	**88.9%**	**89.2%**	**10.8%**	**100.0%**

4-SEC-11

Reference: Exhibit 4-1

Questions: For each affiliate that is providing service to EPCOR, for each year, please provide the total transfer of funds from EPCOR.

Responses: See EPCOR's response to 4-Staff-14 a).

4-SEC-12

Reference: Exhibit 4-1-1, Schedule 4

Questions: Please revise Schedule 4 to include the impact of Bill C-97 and the most recent Federal budget.

Responses:

The following table would be included in Exhibit 4 Tab1 Schedule 4 to illustrate the net impact of Bill C-97.

Table 4-SEC-12-1
Federal Carbon Tax
(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1	Federal Carbon Tax Revenue	212	1,682	2,580	3,557	3,762	3,878	3,926	3,933	3,939	3,944
Row 2	Federal Carbon Tax Expense	-212	-1,682	-2,580	-3,557	-3,762	-3,878	-3,926	-3,933	-3,939	-3,944
Row 3	Net Impact	0	0	0	0	0	0	0	0	0	0

4-SEC-13

Reference: Exhibit 4-3-1, p.31

Questions: Please explain how EPCOR's gas supply plan strategy and execution differs from its gas supply plan strategy and execution for its Aylmer service territory.

Responses:

In the Aylmer service territory, the M9 service provides a fully bundled, no-notice delivery service that includes, transportation, seasonal storage, daily load balancing, and gas commodity. EPCOR's strategy is to annually re-determine its Contract Demand requirements to meet its design day requirements. This service is straightforward and administratively simple to use and has met the needs of EPCOR and its customers.

The M17 service is a new service proposed by Enbridge for the Southern Bruce area and has yet to be approved by the OEB, so final terms are as yet unknown. Unlike the M9 service, the proposed M17 service is a fully unbundled, point to point, transportation service, which requires EPCOR to contract separately for transportation service, and ancillary services including season storage service, daily balancing service and gas commodity. While Enbridge has proposed to offer a market priced service for seasonal storage and balancing independent from the transportation service, the commercial details are not fully understood as to how the market priced balancing services will integrate with the M17 transportation service. EPCOR understands that integrating these services would result in some of the characteristics of a no-notice service, reducing the need to nominate for daily consumption volumes. EPCOR also understands that practically it must acquire this market priced balancing service from Enbridge in order to get this no-notice type service.

While a combination of the M17 transportation and market priced balancing may approach a no-notice service there will still be additional costs incurred by system gas and direct purchase customers to accommodate any daily imbalances between supply deliveries to Enbridge at Dawn and Enbridge re-deliveries back to EPCOR at Dornoch. These additional costs will include i) ensuring that sufficient storage resources are contracted for in order to manage the daily and cumulative imbalance as well as ii) variable costs associated with injection and withdrawal volumes. This will increase the complexity of the service for both system gas customers as well as direct purchase customers. Because of the added complexity of the M17 service, EPCOR will have increased administrative costs to plan, procure services, nominate, and track imbalances. EPCOR is considering whether these functions are best managed in-house or whether it should retain an external gas supply manager to provide this function.

Also, see response to 4-VECC-5.

6-SEC-14

Reference: Exhibit 6

Preamble: *EPCOR states that there will be a shortfall in revenue collected during the stability period due to a delay in the OEB decision.*

Questions:

(a) Is EPCOR referring to the leave to construct or the rates application decision that is delayed?

(b) When did EPCOR originally expect the OEB decision to be rendered and what is the new forecast date that is the basis for its foregone revenue calculations?

(c) Please explain why ratepayers should bear the cost of the delay.

Responses:

(a) EPCOR is referring to the leave to construct decision that is delayed.

(b) EPCOR's CIP forecasted the OEB decision to be made in August 2018 (see Exhibit 6, page 2, Table 6-1, row 5). The new forecast date is July 2019.

(c) Please see Exhibit 6 paragraphs 1 - 5 for a detailed discussion as to why the risk of timing of OEB decisions was not a risk that was transferred to, or accepted by, the proponents of the OEB's competitive process.

7-SEC-15

Reference: Exhibit 7-1-2

Questions: Please provide the excel spreadsheet behind the Cost Allocation Study with all formulas enact.

Responses: See tab "EXHIBIT 7" tab of EPCOR's filed Excel workbook titled "EPCOR 2019 Financial Model Protected_20190412".

8-SEC-16

Reference: Exhibit 8-1-1

Questions: EPCOR states that in designing the fixed charge portion of an average customer's bill it considered a number of listed factors. Yet, the evidence does not explain how those factors resulted in the fixed/variable split that it chose. Please provide further details to explain the basis of its decision.

Responses:

Please see OEB 8.Staff.26.

10-SEC-17

Reference: Exhibit 10-1-1

Questions: If the Board generically changes the methodology for calculation in its inflation factor during the 10 year term, is EPCOR's proposal in this application that it retain the current 2-factor methodology or, that it adopt whatever generic Board inflation factor that may exist in any given year?

Responses:

If the Board generically changes the methodology for calculation in its inflation factor during the 10-year term, EPCOR intends to make an application to adopt the new generic Board inflation factor.

10-SEC-18

Reference: Exhibit 10-1-1, p.4

Questions: Please explain why EPCOR believes it is appropriate to have a Y-Factor for participation in Board hearings.

Responses:

See response to 9.Staff.35.

10-SEC-19

Reference: Exhibit 10-1-1, p.6

Questions: With respect to an ICM:

(a) At this time, does EPCOR foresee any potential capital expenditures during the next 10 years that could result in an ICM? If so, please provide details.

(b) Please provide the ICM threshold calculation for each year of the stability period.

Responses:

(a) At this time, EPCOR does not foresee any potential capital expenditures during the next 10 years that could result in an ICM.

(b) Please see OEB 10.Staff.43.

1-VECC-1

Reference: E2/T2/S1/ pg. 62

Questions:

(a) Please compare/contrast the proposed scorecard with that agreed to recently by EPCOR/ENGLP in EB-2018-0336.

(b) Please compare/contrast the proposed scorecard with that most recently approved for Union/Enbridge.

Responses:

(a) See response to 1.Staff.5. EPCOR Southern Bruce has agreed to add 'total cost per customer per year' and 'total cost per km of distribution pipe per year' to its proposed scorecard. The revised proposed scorecard provided in 1.Staff.5 Attachment 1 aligns with the scorecard recently agreed to for 2020-2024 in the settlement proposal dated June 10, 2019 for EPCOR's distribution rates application for its Aylmer operation (EB-2018-0336).

(b) The revised proposed scorecard provided in 1.Staff.5 Attachment 1 aligns with the scorecard most recently approved for Union/Enbridge in EB-2017-0306/0307 in the areas of Customer Focus and Financial Performance. The proposed scorecard for EPCOR Southern Bruce does not include the Operational Effectiveness measure which Union/Enbridge's has related to transmission compression as this measure is not applicable to EPCOR Southern Bruce. With respect to the measures related to Public Policy Awareness, EPCOR Southern Bruce's proposed scorecard includes a number of measures which Union/Enbridge's scorecard does not have ('new communities that have access to the distribution system', '$/m3 cost to deliver natural gas', 'customer years', and 'cumulative volume') while Union/Enbridge's scorecard has a measure of 'Total Cumulative Cubic Meters of Natural Gas Saved' associated with its demand side management program which is not applicable for EPCOR Southern Bruce.

2-VECC-2

Reference: E2/T2/S1

Questions:

(a) Is it still EPCOR's expectation to have gas service for Kincardine by the beginning of the 2019 winter season?

(b) Has Union (Enbridge) begun construction on the Dornoch Meter Station?

Responses:

(a) No. EPCOR's current expectation is that it will have service to the Bruce Energy Center by end of 2019. EPCOR's current schedule was included in its leave to construct application (EB-2018-0263, Exhibit A, Tab 6, Schedule 2, page 1). Gas service for Kincardine is expected for the 2020 winter season.

(b) Enbridge has begun construction of the Dornoch Meter Station. EPCOR understands that this station will be in service in November 2019.

3-VECC-3

Reference: E3/T1/S1/pg.15

Questions:

(a) What is the time period for which EPCOR will not charge any connection fees? Is this term set out in the Utility's terms of service or otherwise in the proposed tariff of the Utility?

Responses:

EPCOR expects not to charge any connection fee during the 10-year rate stability period. This term is not set out in the Utility's terms of service or otherwise in the proposed tariff of the Utility. EPCOR understands that it would require OEB approval to change any miscellaneous charge in its terms of service if they are approved in the application.

3-VECC-4

Reference: E3/T1/S3 pg. 3

Questions:

(a) Please clarify what is mean by “line strikes” as noted in footnote 11 at this reference.

Responses:

(a) A “line strike” is when an installed line is compromised by a third party digging in the area. Under certain circumstances, the third party will be billed to repair the line.

4-VECC-5

Reference: E3/T1/S1/pg. 14 & E4/T3/S1/ EPCOR Gas Supply Plan

Questions:

(a) In EPCOR's view would the availability of M9 service be preferable to Union's (Enbridge) proposed M17 service? Please explain why one might be preferable to the other.

(b) If M9 service were available to EPCOR South Bruce how might this alter the gas supply plan?

(c) Does Union (Enbridge) have a Board approved M17 Rate? If not when is approval for this rate expected?

Responses:

(a) In EPCOR's view the availability of the M9 service would be preferable for its customer's versus Enbridge's proposed M17 service. The M9 is a bundled service that includes cost based services such as transportation, seasonal storage, daily load balancing and is a no-notice service that doesn't require daily nominations (other than to nominate gas deliveries to Enbridge in the event that a customer opts to purchase its own gas supply). M9 service also provides the customer the option to purchase gas commodity from Enbridge.

The M17 service is a fully unbundled service which is basically a point-to-point transmission only service, excluding the other features of M9 as described above. EPCOR, and its direct purchase customers, will need to submit daily nominations for supply as well as expected next day consumption requirements. The proposed M17 service excludes access to cost based storage, any daily balancing provision or access to the gas commodity. In ongoing discussions with Enbridge, they have verbally offered to provide a market-priced storage and balancing service as an add-on to M17 (although to date, EPCOR has not received sufficient written detail to fully understand how this market-based balancing service would be integrated into the M17 service). This balancing function is practically only available from Enbridge and there could be long term pricing risk with the service which would be a cost to customers. Under the proposed M17 service, EPCOR expects that it will have to hold daily balancing resources to accommodate the differences between supplies into the system and daily consumption, for both system gas customers as well as direct purchase customers. These daily imbalances may result in additional storage charges that will need to be tracked and assigned to direct purchase and non-direct purchase customers.

Access to the M9 bundled service would tend to reduce the total costs of storage and balancing and internal administrative costs and reduce complexity of the upstream service for EPCOR and its direct purchase customers. Any costs or cost savings incurred for upstream transportation, storage, balancing services, and administrative costs would be passed on to the rate payer.

(b) See (a) above.

(c) Enbridge does not have a Board approved M17 Rate (EB-2018-0244). At this time Enbridge is proposing to refile its M17 rates application with the leave to construct for its Owen Sound reinforcement project. EPCOR understands that Enbridge intends to proceed with that filing in mid July.

4-VECC-6

Reference: E4/T2/S1/ Service Level Agreement (SLA)

Questions:

(a) Has EPCOR provided Schedule “A” a list of the contract services to the SLA provided at the above reference? If not please provide this schedule.

Responses:

(a) EPCOR Southern Bruce has not yet entered into Service Level Agreements with its affiliates and as such these schedules have not been drafted. For information on the corporate and affiliate shared services see the details provided in Exhibit 4, Tab 1, Schedule 1 pages 22 through 56 and the breakdown of the services and costs provided in response 4.Staff.14 (a).

7-VECC-7

Reference: E7/T1/S1/pg.15

Questions:

(a) Please explain why the proposed rates are not being adjusted to bring revenue-to-cost-ratios for all four class to 1 or near 1.

Responses:

(a) Please see OEB 7.Staff.22.

8-VECC-8

Reference: E8/T2/S1/pg.23 - Conditions of Service

Questions:

(a) Using Table 20 filed at page 27 EPCOR/ ENGLP's EB-2018-0336 recently filed settlement agreement please add a column shown EPCOR Southern Bruce Summary of Service and Miscellaneous Charges.

(b) Please explain the rationale for any differences in the charges as between the two Utilities in these charges.

Responses:

(a) See response to 8.Staff.25.

(b) See response to 8.Staff.25.

9-VECC-9

Reference: E9/T1/S1/pg.5

Questions:

(a) Please confirm (or correct) that the Regulatory Expense Deferral Account (REDA) is to capture only those regulatory costs imposed upon EPCOR. That is, the account will not record regulatory costs incurred for applications filed by EPCOR South Bruce for rate changes or other purposes.

Responses:

(a) Confirmed, the REDA is to only capture the regulatory costs it incurs that are associated with participating in generic hearings that impact the utility, and Enbridge Gas' (Union Gas') proceedings.

9-VECC-10

Reference: E9/T1/S1/pg.5

Questions:

(a) What is the reason for seeking a Municipal Tax Variance Account (MTVA)? For example, EPCOR Southern Bruce is not seeking variance accounts for potential changes to other types of taxes (e.g. income) or tax rates.

(b) Why does EPCOR believe this account will attract material balances?

Responses:

(a) See response to 9.Staff.36 (a).

(b) See response to 9.Staff.36 (b).

Anwaatin 1

Reference: Exhibit 1, Tab 2, Schedule 1, p. 9

Preamble: *EPCOR states in the Application that one of its goals in bringing the Southern Bruce system online is to "[e]ffectively engage and consult with key stakeholders and First Nations and Metis communities".*

Questions:

(a) Please describe how EPCOR consulted First Nations or other Indigenous communities (including the Saugeen Ojibway Nation (SON)) on any and all investment/ownership opportunities and other business partnership opportunities related to the Southern Bruce system and what resulted from these consultation efforts. Please provide all supporting documentation.

(b) Please describe in detail and provide all reports, notes, memos and documents related to:

i. all processes EPCOR undertook to consult with Indigenous communities (including the SON) on this Application;

ii. the outcome of those consultations.

Responses:

(a) In discussions with the Saugeen Ojibway Nation (SON) in December 2015, the SON inquired if EPCOR Natural Gas Limited Partnership (ENGLP) was interested in an investment partner or selling an equity stake in the project. ENGLP indicated that it was not looking for an equity partner at the time. No other First Nations or other Indigenous communities raised potential investment/ownership or business partnership opportunities.

(b) A summary of ENGLP's First Nations and Metis community consultation in respect of the South Bruce Project can be found in EPCOR's leave to construct application (EB-2018-0263, Exhibit A, Tab 11) as well as ENGLP's responses to the Anwaatin interrogatories 1, 2 and 6 in that application. The focus of those consultations was on understanding the physical work associated with construction and impacts on any treaty or aboriginal rights of communities on the consultation list. As a result, discussions were largely related to potential environmental impacts and archaeological resources. During the 10-year term of this rate application, EPCOR is not expecting the distribution system to serve any indigenous community.

Anwaatin 2

Reference: Exhibit 1, Tab 1, Schedule 1, p. 7
Common Infrastructure Proposal, paras. 45-46

Preamble: *The Board indicated in its Decision and Order in EB-2016-0137/0138/0139 that it "will require EPCOR to demonstrate that forthcoming leave to contract and rates applications are consistent with its [Common Infrastructure Proposal (CIP)] proposal".*

In its CIP, EPCOR identified the following First Nations and Métis communities (para. 45):

- *Saugeen First Nation*
- *Chippewas of Nawash Unceded First Nation*
- *Metis Nation of Ontario Great Lakes Metis Council*
- *Historic Saugeen Metis*
- *Beausoleil First Nation*
- *Chippewas of Kettle and Stony Point First Nation*

EPCOR stated that "[o]nce EPCOR has been chosen as the successful proponent, EPCOR will work closely with these First Nations and Metis Communities on involvement in the successful outcome of this project" (para 46).

Questions:

(a) Please describe in detail, and provide all reports, notes, memos and documents related to, EPCOR's work in relation to the Application with the identified First Nations and Métis communities and their involvement in the successful outcome of the project.

Responses:

(a) Please see responses to Anwaatin 1 (a) and (b).

Anwaatin 3

Reference: Exhibit 1, Tab 2, Schedule 1, p. 17

Preamble: *On December 21, 2018, EPCOR received confirmation that the Southern Bruce expansion project is eligible for rate protection as available through the recently enacted Access to Natural Gas Act, 2018, SO 2018, c 15 (Bill 32). On March 7, 2019, the Government of Ontario filed Ontario Regulation 24/19 Expansion of Natural Gas Distribution Systems (the Regulation) which stated in Schedule 1 that the Southern Bruce Project was eligible for up to $22.0 million. The regulation is scheduled to come into force July 1, 2019.*

The majority of First Nations in Ontario do not have access to natural gas, and many First Nations are interested in accessing natural gas for energy cost savings and low-emission heating. The recently enacted Bill 32 provides a framework for regulations to deliver rate protection for consumers or prescribed classes of consumers with respect to costs incurred by natural gas distributors in making a qualifying investment for the purpose of providing access to a natural gas distribution system to those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Questions:

(a) What rate impacts will EPCOR's Application have on the provision of natural gas to off-reserve First Nation members in the region?

(b) What rate impacts will EPCOR's Application have on the cost of natural gas to off-reserve First Nation members in the region?

(c) How is EPCOR utilizing the framework provided by Bill 32 and the Regulation to deliver rate protection and cost reductions for consumers in the Application?

(d) How does EPCOR envision itself or other distributors using Bill 32 for natural gas system expansions beyond those expansions currently identified in the Regulation?

Responses:

(a) EPCOR is unaware of any residential customers in the region that currently use natural gas and as a result is unable to provide a forecast of rate impacts.

(b) See (a) above.

(c) The Southern Bruce project is uneconomic without the funding provided through Bill 32. Exhibit 3.2.3 page 11, Table 3-5 details how the $22.0 million contribution will reduce the 10-year revenue requirement for this project. This reduction in revenue requirement thereby reduces rates and increases the affordability of natural gas in the region.

(d) EPCOR understands that funding parameters for expansions not currently identified in the Regulation have not been confirmed and is therefore unable to detail how it might be used.

Anwaatin 4

Reference: Exhibit 1, Tab 2, Schedule 1, p. 29
Exhibit 2, Tab 2, Schedule 1, pp. 5-6
Exhibit 3, Tab 2, Schedule 2, p. 18
Exhibit 3, Tab 2, Schedule 2, p. 63

Preamble: *The County of Bruce Official Plan is available at the following link: https://brucecounty.on.ca/sites/default/files/County%20Plan_Consolidated_September%202017_2.pdf. The County of Grey Official Plan is available at the following link: https://www.grey.ca/planning-development.*

Questions:

(a) Does the Application, including any model franchise agreements, consider the requirements and general direction of the County of Bruce Official Plan?

(b) Please describe in detail the aspects of the Application (and the broader construction and operation of the Southern Bruce system) that account for the requirements and general direction of the County of Bruce Official Plan.

(c) Does the Application, including any model franchise agreements, consider the requirements and general direction of the County of Grey Official Plan?

(d) Please describe in detail the aspects of the Application (and the broader construction and operation of the Southern Bruce system) that account for the requirements and general direction of the County of Grey Official Plan.

Responses:

(a) – (d) These questions are not relevant to the OEB's determination of just and reasonable rates. ENGLP further notes that matters relating to the applicable franchise agreements for the Southern Bruce system are being considered by the OEB in ENGLP's leave-to-construct application (EB-2018-0263).