2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

May 1, 2020

Alberta Utilities Commission
10th Floor, 10055 – 106 Street
Edmonton, AB T5J 2Y2

Attention: **Mr. Blair Miller**
Executive Director, Rates

Dear Mr. Miller:

Re: EPCOR Energy Alberta GP Inc.
Rule 005 – Annual Reporting Requirements of Financial and Operational Results for 2019.

1. EPCOR Energy Alberta GP Inc. ("EEA") provides the attached copy of its Alberta Utilities Commission ("AUC") Rule 005 Annual Financial and Operating Report package for 2019.

2. The package includes the following files:

Appendix A – Financial and Operational Results Schedules
Appendix B – Variance Explanations
Appendix C – Audited Financial Statements for EPCOR Energy Alberta Limited Partnership

3. Please contact me at (780) 412-4449 if you have any questions.

Sincerely,

[Electronically Submitted]

Pamela Zrobek
Treasurer & Controller, Energy Services
EPCOR Energy Alberta GP Inc.

Attachments

EPCOR Energy Alberta GP Inc.

AUC RULE 005: ANNUAL REGULATED RATE TARIFF (RRT) FINANCIAL AND OPERATIONAL RESULTS

FOR THE YEAR ENDED DECEMBER 31, 2019

TABLE OF CONTENTS

Purpose of RRT Schedules

Schedule 1 – Net income statement
To provide a high level breakdown of revenues and expenses associated with the provision of the regulated rate tariff electricity services including the net income (or return) achieved by the providers both including and excluding any regulatory cost disallowances.

Schedule 2 – Revenue by customer class
To provide a detailed revenue breakdown of energy, non-energy and flow-through revenue by customer category relevant to each provider.

Schedule 3 – Sites and energy sales by customer class
To provide a breakdown of the average number of sites and energy sales by customer category relevant to each provider.

Schedule 4 - Energy and operating expenses
To provide a detailed breakdown of expenses associated with the provision of regulated retail energy services. Expenses are separated into commodity costs, trading and procurement charges and other non-energy expenses.

Schedule 5 - Debt capital employed and interest expense
To provide actual and allocated debt carrying costs charged to the provider (normally from the parent company) with an adjustment for any regulatory interest cost disallowances.

Schedule 6 - Income tax / PILOT
To provide the detailed tax calculation used to determine the income tax provision or PILOT for the regulated operations of the provider.

Schedule 7 - Capital assets continuity schedule
To provide a summary of capital assets in use and construction work in process (CWIP) assets, including additions, retirements, transfers and any adjustments.

Schedule 8 - Manpower summary
To provide a breakdown of the capitalized and expensed labour costs and human resources as expressed in full time equivalents (FTEs). The costs shown here are embedded in the total operating expense identified in schedule 4.

Schedule 9 – Reserve accounts
To provide a summary of the transactions that occurred in the provider's reserve accounts for the year.

Schedule 10 – Affiliate transactions
To identify transactions with affiliates. Since some providers are not required to report under the inter-affiliate code of conduct (which requires affiliate transaction reporting), this schedule was retained for transparency.

Schedule 11 - Reconciliation from audited income statement to regulatory schedules
To provide a reconciliation from the audited income statement to the regulated rate provider's reported income.

SCHEDULE 1

EPCOR Energy Alberta GP Inc.

REGULATED RATE TARIFF INCOME STATEMENT

FOR THE YEAR ENDED DECEMBER 31, 2019

($000s)

Line No.	Description	Cross-Ref. from	2019	2018	Variance higher/(lower)	Variance %	Variance W/P Ref
	Revenue						
1	Revenue	Sch 2	935,611	873,759	61,853	7.1%	A
2	Revenue offsets and other adjustments	Sch 2	3,999	4,643	(644)	-13.9%	A
3	Total Revenue		939,611	878,402	61,209	7.0%	
	Expenses						
4	Energy and operating expenses	Sch 4	361,761	348,373	13,388	3.8%	see Sch 4
5	Interest	Sch 5	771	375	397	105.8%	A
6	Income tax /Payment in lieu of tax	Sch 6	-	-	-		see Sch 6
7	Depreciation & amortization	Sch 7	4,254	4,433	(178)	-4.0%	B
8	Flow-through expenses	Sch 11	535,634	521,857	13,777	2.6%	A (5)
9	Total Expenses		902,421	875,038	27,383	3.1%	
10	**Regulatory net income/(loss)**	Sch 11	**37,189**	**3,364**	**33,826**	**1005.7%**	
	Reconciliation						
11	Regulatory net income/(loss)	Sch 11	37,189	3,364	33,826	1005.7%	
12	Less: regulatory cost disallowances	Sch 11	1,879	1,403	476	33.9%	C
13	**Adjusted regulatory net income/(loss)**		**35,310**	**1,961**	**33,350**	**1700.9%**	

Notes:

Totalling of columns and rows may be influenced by rounding

SCHEDULE 2

EPCOR Energy Alberta GP Inc.
REVENUE BY CUSTOMER CLASS
FOR THE YEAR ENDED DECEMBER 31, 2019
($000s)

Line No.	Description	Cross-Ref.	2019 Fortis Residential	Farm	Irrigation	Small Comm	Oil Gas	Lighting	EDTI Residential	Small Comm	Lighting	RRT Total	Variance W/P Ref
1	Energy Revenue (Note 1)		133,223	31,210	6,522	49,163	696	281	101,590	41,987	120	364,793	A (1)
2	Final Settlement (Note 2)											(531)	A (1)
3	Non-Energy revenue (Note 3)		15,298	1,714	90	1,929	56	429	15,020	1,082	52	35,670	A (3)
4	Flow-through revenue (Note 4)		207,296	60,482	9,301	78,526	1,335	2,704	129,762	45,562	710	535,679	A (2)
5	Sub-total	Sch 1	355,818	93,406	15,913	129,618	2,087	3,415	246,373	88,631	882	935,611	
	Revenue offsets and other adjustments:												
6	Late Payment Charges		1,500	424	78	559	11	13	922	347	3	3,858	
7	Collection & NSF Fees		267	32	4	29	0	7	269	22	1	632	
8	Connection Fees		402	49	5	44	1	11	697	57	3	1,268	
9	Green Power		2	0	0	0	0	0	2	0	0	5	
10	E-Bill Credit		(748)	(91)	(2)	(82)	(1)	(20)	(756)	(62)	(3)	(1,764)	
11	Total revenue offsets and other adjustments	Sch 1	1,423	415	86	551	11	11	1,134	364	4	3,999	A
12	**Total**	Sch 11										**939,611**	

Line No.	Description	Cross-Ref.	2018 Fortis Residential	Farm	Irrigation	Small Comm	Oil Gas	Lighting	EDTI Residential	Small Comm	Lighting	RRT Total	
1	Energy revenue		115,370	26,497	5,702	42,287	775	259	88,191	36,654	101	315,835	A (1)
2	Final Settlement											(64)	A (1)
3	Non-energy revenue		15,584	1,789	82	1,901	36	447	15,213	1,177	52	36,279	A (3)
4	Flow-through revenue		197,193	61,771	10,982	74,297	1,615	2,481	127,902	44,796	670	521,708	A (2)
5	Sub-total	Sch 1	328,147	90,057	16,766	118,486	2,425	3,186	231,306	82,626	823	873,759	
	Revenue offsets and other adjustments:												
6	Late Payment Charges		1,377	389	72	513	11	12	903	340	3	3,619	
7	Collection & NSF Fees		235	28	3	26	0	7	238	19	1	558	
8	Connection Fees		407	49	5	44	1	11	719	58	3	1,297	
9	Green Power		2	0	0	0	0	0	2	0	0	6	
10	E-Bill Credit		(355)	(43)	(1)	(39)	(1)	(10)	(358)	(29)	(1)	(837)	
11	Total revenue offsets and other adjustments	Sch 1	1,667	424	79	545	11	20	1,503	388	5	4,643	A
12	**Total**	Sch 11										**878,402**	

Notes:

Note 1 Total Energy revenues of $364,792,683 includes energy and non-energy return margin totaling $15,471,017, please see breakdown below for the after tax and pre-tax return rate. There are 3 rates in 2019 due to January to March return rate being based on 2016-2018 EPSP, April to June return rate was based on new calculation for the first half of the year under the new 2018-2021 EPSP and July to December return rate was based on new calculation for the second half of the year.

	After Tax Return Rate	Pre-Tax Return Rate	Energy Sale	Pre-Tax Margin
	($ / MWh)	($ / MWh)	(MWh)	($)
January to Ma	2.51	3.438	1,344,265	4,621,582
April to June	2.003	2.743	1,053,790	2,890,545
July to Decen	2.558	3.457	2,302,253	7,958,889
Total			4,700,308	15,471,017

Note 2 Total Final Settlement of $(530,624) includes energy revenue, flow-through revenue and non-energy revenue related to prior period. Flow-through was reported as net revenue in 2019 financial statement, but not reported as net in Rule 005.

Note 3 Total Non-energy revenue is $35,670,289.

Note 4 Total Flow-through revenue of $535,678,866 includes LAF, A-1 Rider, and MFF revenue totaling $34,611,394.20

Line No.	Line Item Definitions:
1	Energy revenues: revenue associated with the energy charges billed.
2	Final settlement is revenues billed to customers in the current year for prior year consumption.
3	Non-energy revenue: revenue associated with administration charges or customer charges (billed at a fixed amount per day or month).
4	Flow-through revenue: revenue associated with the total distribution tariff, transmission tariff, franchise fee, and local access fee charges billed to customers, on behalf of the distribution utility.
6	Late Payment Charges: revenue associated with the collection of late fees charged to accounts when customers do not pay their bill on time.
7	Collection fees is where EEA delivers a "Turn-Off Notice" to a customer due to non-payment. NSF fees are charged where a customer's payment is not honoured by the customer's bank or financial institution
8	Connection fees related to charges applied for an expedited connection or a reconnection of service after cut-off for non-payment.

SCHEDULE 3

EPCOR Energy Alberta GP Inc.

SITES AND ENERGY SALES BY CUSTOMER CLASS

FOR THE YEAR ENDED DECEMBER 31, 2019

Line No.	Description	2019 Fortis Residential	Fortis Farm	Fortis Irrigation	Fortis Small Comm	Fortis Oil Gas	Fortis Lighting	EDTI Residential	EDTI Small Comm	EDTI Lighting	RRT Total
1	Sites - average	235,143	28,478	3,165	25,927	327	6,373	237,721	19,428	862	557,425
2	Energy sales (MWh)	1,734,075	406,791	78,394	629,251	9,421	4,713	1,299,121	536,522	2,020	4,700,308
3	Energy sales per site (kWh/site)	7,375	14,285	24,770	24,270	28,783	739	5,465	27,615	2,343	8,432

Line No.	Description	2018 Fortis Residential	Fortis Farm	Fortis Irrigation	Fortis Small Comm	Fortis Oil Gas	Fortis Lighting	EDTI Residential	EDTI Small Comm	EDTI Lighting	RRT Total
1	Sites - average	241,589	29,162	3,141	26,415	384	6,750	243,775	19,668	893	571,777
2	Energy sales (MWh)	1,820,404	421,860	81,177	653,037	12,384	5,275	1,367,729	566,788	2,059	4,930,712
3	Energy sales per site (kWh/site)	7,535	14,466	25,844	24,722	32,228	781	5,611	28,817	2,306	8,623

Line No.	Line Item Definitions:
1	Sites - average: number of sites based on monthly average for the calendar year. A "site" is generally defined as being the finest or lowest level of consumption or usage data. A "site" generally represents a meter installation.
2	Energy sales (MWh): total energy billed and accrued for the applicable customer class.
3	Energy sales per site (kWh/site): line 2 multiplied by 1,000 and divided by line 1.

SCHEDULE 4

EPCOR Energy Alberta GP Inc.

ENERGY AND OPERATING EXPENSES

FOR THE YEAR ENDED DECEMBER 31, 2019

($000s)

Line No.	Description	Cross-Ref. from	2019	2018	Variance higher/(lower)	Variance %	Variance W/P Ref
	Physical spot market						
1	AESO - energy charges		287,748	273,084	14,664	5.4%	
2	AESO - retail adjustment to market (RAM)		(47)	(2)	(45)	2069.8%	
3	AESO - trading charges		2,222	1,357	865	63.7%	
4	AESO - uplift charges		125	109	17	15.3%	
5	AESO - other		(14)	1	(15)	-2986.6%	
6	NGX Trading		462	380	82	21.6%	
7	Net Hedging		31,625	35,966	(4,341)	-12.1%	
8	Total Energy Expenses		**322,120**	**310,894**	**11,226**	**3.6%**	A (4)
	Other operating expenses (Note)						
9	Credit costs	Sch 10	2,404	2,069	335	16.2%	B
10	Billing & customer care		24,333	24,498	(165)	-0.7%	B
11	Corporate allocations	Sch 10	4,916	4,620	297	6.4%	B
12	Operational and administration costs		2,794	2,778	16	0.6%	B
13	Bad debt expense (Note 1)		5,054	3,604	1,450	40.2%	B
14	Hearing costs (Note 2)	Sch 9	138	(91)	229	-252.4%	B
15	Other						
16	Total energy and operating expense		**361,761**	**348,373**	**13,388**	**3.8%**	(to Sch 1)

Notes:

The expenses reported above should exclude regulatory disallowances, as defined on schedule 11. Any disallowed expenses should be reported on schedule 11, column G.

Note 1 Bad debt expense as presented includes accounting adjustments for recognized bad debt expense.

Note 2 In order to make the expense realized for line 14 above agree to the "Recovery through rates" in Schedule 9 column "G" row 1, the required amount reported in line 14 above was reclassified from line 12, "Operational and administration costs".

Line No.	Line Item Definitions:
1	AESO - energy charges: the cost of energy (electricity) based on hourly consumption and hourly pool prices as calculated by the AESO and identified on the AESO pool statement.
2	AESO - retail adjustment to market (RAM): charges related to a post final adjustment mechanism (PFAM) made in the settlement of load, for the collection/payment required to offset the RSA (retailer specific adjustment) as identified on the AESO pool statement.
3	AESO - trading charges: total trading charges applicable to power pool transactions.
4	AESO - uplift charges: total annual uplift charges as calculated by the AESO and identified on the AESO pool statement.
5	AESO - other: includes all charges on the AESO pool statement not included in any other line item above.
6	NGX - trading charges/auction fees: any charges or fees associated with electricity contracts traded on the NGX.
7	Net hedging cost (revenue): includes costs or revenues associated with financial contracts (e.g. financial swaps) facilitated by an exchange or broker.
9	Credit costs: costs associated with collateral requirements (parental guarantee, letter of credit) trading exchanges or counterparties.
10	Billing & customer care: costs related to billing, call centre and other customer support functions.
11	Corporate allocations: allocated corporate overhead based on AUC approved methodologies.
12	Operational and administration costs: expenses associated with the management of the RRT, including salaries, consultant fees, and travel expenses.
13	Bad debts expense: the amount of non-collectible accounts receivable associated with RRT billings.
14	Hearing costs: costs associated with proceedings for RRT applications that are approved by the Commission.
15	Other: includes all expenses not accounted for in line items above. Please identify.

EPCOR Energy Alberta GP Inc.
DEBT CAPITAL EMPLOYED AND INTEREST EXPENSE
FOR THE YEAR ENDED DECEMBER 31
($000s)

2019

Line No.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Net Underwriting Discount/(Premium) & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Interest Expense
	Long term- debt										
1	Intercompany Debt (IC-EUI-75-00		8/28/2014	8/28/2024	4.67%	20,000		20,000	0.00%	20,000	933
2	Total long-term debt					20,000	-	20,000	0.00%	20,000	933
3	Total short-term debt								0.00%		(303)
4								Less: interest related to non-regulatory			(226)
5								Less: regulatory interest cost disallowance			367
6								**Total interest expense**			**771** (to Sch 1, Note 1)

Note 1 - RRT Regulatory Interest expense presented consists of cost of debt of $244 thousand and working capital of $527 thousand.

2018

Line No.	Description	Series	Issue Date	Maturity Date	Coupon Rate	Principal Amount	Net Underwriting Discount/(Premium) & Expense	Total Amount	Effective Cost Rate %	Principal Outstanding at Year-End	Interest Expense
	Long term- debt										
1	Intercompany Debt (IC-EUI-75-00		8/28/2014	8/28/2024	4.67%	20,000		20,000	0.00%	20,000	933
2	Total long-term Debt					20,000	-	20,000	0.00%	20,000	933
3	Total short-term Debt								0.00%		(108)
								Less: interest related to non-regulatory			(282)
								Less: regulatory interest cost disallowance			(168)
								Total interest expense			**375** (to Sch 1, Note 2)

EPCOR Energy Alberta GP Inc.
INCOME TAX/PAYMENT IN LIEU OF TAXES (PILOT)
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Description	Cross-Ref. from	2019	2018	Variance higher/(lower)	Variance %	Variance W/P Ref
1	Income for RRT (before taxes) (Note 1)		35,310	1,960	33,350	1701.1%	B
2	Permanent differences		(35,310)	(1,960)	(33,350)	1701.1%	B
3	Timing differences		-	-	-		B
4	Taxable Income		-	-	-		
5	Combined tax rate		26.50%	27.00%			
6	Current tax provision or PILOT (flow-through method)		-	-	-		B
7	Adjustments to current tax provision		-	-	-		B
8	Future income tax provision (if applicable)		-	-	-		B
9	**Total Income Tax Provision**	Sch 11	**-**	**-**	**-**		(to Sch 1)

	2019	2018
Tax rates:		
Federal	15.0%	15.0%
Provincial	11.5%	12.0%
Combined	26.5%	27.0%

Notes:

Note 1 EEA LP is not taxable after the February 2014 reorganization to EEA LP.

Line No.	Line Item Definitions:
1	Income for RRT (before taxes): the Regulated Rate Tariff income before tax deductions.
2	Permanent differences: amounts recorded in revenue and expenses that are neither taxable nor deductible in accordance with income tax legislation.
3	Timing differences: amounts recorded in revenue and expense for accounting purposes in a period that does not coincide with the taxation year in which the related amounts are allowed in computing net income for income tax purposes (example, depreciation and amortization included for accounting purposes and capital cost allowance allowed for income tax purposes).
4	Taxable income: the amount of income for RRT adjusted for permanent and timing differences, used in the calculation to determine the current tax payable (line 6).
5	Combined tax rate: combined federal and provincial tax rate in accordance with applicable tax legislation.
6	Current tax provision or PILOT: the income taxes that the utility would pay to the provincial or federal governments if the entity is considered to be a taxable Canadian corporation, or, if the entity is owned by a municipality, it is the amount to be paid to the Balancing Pool under the Payment In Lieu Of Taxes regulation AR 112/2003 and is equal to the amounts determined in accordance with the federal and Alberta income tax legislation.
7	Adjustments to current tax provision: can include prior or current year (over)/under provisions or any other adjustments. Provide a detailed explanation of any adjustments reported.
8	Future income tax provision (if applicable): provide a detailed explanation of amount reported.
9	Total income tax provision: the amount shown in line item 6 on schedule 1, as the total income tax expense recognized for regulatory purposes as approved by the AUC.

EPCOR Energy Alberta GP Inc.
CAPITAL ASSETS CONTINUITY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31
($000s)

CAPITAL ASSETS

Line No.	Property Group	Balance at 12/31/2018	2019 Additions	2019 Retirements	2019 Transfers	2019 Adjustments	Balance at 12/31/2019
1	Hardware	-	-	-	-	-	-
2	Leasehold Improvements	337	80	-	-	-	417
3	Telephone System	1,488	43	(15)	-	-	1,516
4	Office Furniture and Equipment	958	4	-	-	-	962
5	Computer Equipment	1,750	326	(133)	-	2	1,944
6	Software	18,117	1,936	(1,652)	-	(2)	18,399
7	Customer Rights	51,229	-	-	-	-	51,229
8	**Subtotal**	73,879	2,389	(1,800)	-	-	74,468
9	Capital Work In Progress (CWIP)	210	2,479	-	(2,389)	-	300
10	**Total Utility**	**74,089**	**4,868**	**(1,800)**	**(2,389)**	**-**	**74,767**

ACCUMULATED DEPRECIATION

Line No.	Property Group	Balance at 12/31/2018	Depreciation Expense	2019 Retirements	2019 Net Salvage	2019 Adjustments	Balance at 12/31/2019
11	Hardware	-	-	-			-
12	Leasehold Improvements	93	20	-			113
13	Telephone System	1,023	77	(15)			1,085
14	Office Furniture and Equipment	367	87	-			455
15	Computer Equipment	643	465	(131)		0	978
16	Software	8,167	4,147	(1,652)		(0)	10,661
17	Customer Rights	46,121	2,554	-			48,675
18	**Total**	**56,414**	**7,351**	**(1,798)**	**-**	**-**	**61,967**

19	Unreconciled difference	-		Net Assets	12,801
20	Depreciation / amortization adjustment for non-RRT	1,777			
21	Proceeds from transfer of assets	3			
22	Disallowed Depreciation	1,319			
23	Total depreciation and amortization expense	**4,254**	(to Sch 1)		

No.	Line Item Definitions:
1-8	Asset classifications are not universally defined for RRT providers. Each provider is to include additional asset classification line items to those shown above as deemed necessary.
9	Capital Work In Progress / Assets Under Construction: the balance of expenditures recorded for capital projects that are still in progress at year end.
11-18	Accumulated depreciation reported by asset classifications as reported under capital assets. Depreciation expense also appears on Schedules 1 and 11.
19-21	This line is to account for any necessary adjustments to reconcile line 22 to line 7 on schedule 1. If adjustments are made, an explanation should be provided as to the nature of the adjustments.
22	The total depreciation & amortization amount is the result of the total on line 18, with recognized losses on disposal of assets on retirements, less any adjustment entered on lines 20 and 21. The breakdown is as follows:

Depreciation Expense for 2019 (Line 18)	7,351
Add: Loss recognized on retired assets & transfer proceeds (Line 10 less L	0
Less: Adjustment for non-RRT (Line 20)	(1,777)
Less: Disallowed Depreciation (Line 21)	(1,319)
Total depreciation and amortization expense - RRT	**4,254**

EPCOR Energy Alberta GP Inc.
MANPOWER SUMMARY
FOR THE YEAR ENDED DECEMBER 31

COST OF MANPOWER

Line No.	Description	2019	2018	Variance higher/(lower)	Variance %	Variance W/P Ref
1	Salaries and wages	25,208	21,956	3,252	14.8%	
2	Employee benefits	6,280	6,203	78	1.3%	
3	Contracted labour			-		
4	Gross manpower expenses	31,488	28,158	3,329	11.8%	
5	Less: Capitalized manpower (Note 1)	3,230	847	2,383	281.2%	
6	Less: Other reductions in manpower (specify)					
7	**Net manpower operating expense**	**28,257**	**27,311**	**946**	**3.5%**	B

FULL TIME EQUIVALENTS (FTEs)

Line No.	Description	2019	2018	Variance higher/(lower)	Variance %	
8	Regular employees - gross	310.5	268.6	41.9	15.6%	
9	Temporary employees - gross			-		
10	Contract staff - gross			-		
11	Gross FTEs	310.5	268.6	41.9	15.6%	
12	Less: Capitalized manpower (Note 1)	24.1	6.8	17.3	255.0%	
13	Less: Other reductions in manpower (specify)	-	-	-		
14	**Net operating FTEs**	**286.5**	**261.8**	24.6	9.4%	B

Note: The values provided in this schedule for salaries, wages, benefits and FTEs are at the gross level as EEA GP does not have employees dedicated specifically to the provision of services to just the RRT customers. Rather, these costs are pooled and allocated to the RRT customers based on a cost-causation analysis.

Note 1 Capitalized manpower on line 5 and 12 have been restated for 2018 to include capital transfers to the CIS project.

Line No.	Line Item Definitions:
1	Salaries and wages: the total amount of salaries and wages (full time, temporary and casual employment) charged to the provider that support the gross full time equivalents presented in line 8. This value does not include the cost of salaries and wages embedded in corporate cost allocated to the provider.
2	Employee benefits: the total amount of employee benefits in addition to the total salaries and wages in line 1.
3	Contracted labour: the total amount of contracted labour. Where contractor charges include both materials and labour, only the labour component of the charges shall be included in this line.
5	Capitalized manpower: the total amount of salaries, wages, benefits and contracted labour charges in lines 1, 2 and 3 that were capitalized.
6	Other reductions in manpower: reductions to the gross manpower expenses not accounted for under capitalized manpower (line 5).
8	Regular employees - gross: the number of full time equivalent (FTE) positions related to the salaries and wages of regular (permanent) employees (either full or part-time) in line 1 above.
	FTE values presented are based on initial analysis and may be subject to classification changes for presentation in future non-energy applications.
9	Temporary employees - gross: the number of FTE positions related to the salaries and wages of temporary employees in line 1 above.
10	Contract staff - gross: the number of FTE positions related to the contracted labour expense in line 3 above.
12	Capitalized manpower: the number of FTE positions related to the total amount of salaries, wages, benefits and contracted labour charges capitalized in line 5.
13	Other reductions in manpower: reductions to the gross FTEs not accounted for under capitalized manpower (line 12).

SCHEDULE 9

EPCOR Energy Alberta GP Inc.
RESERVE ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Description	Balance at 12/31/2018	Costs incurred	Recovery through Rates	Balance at 12/31/2019	
		(Note 1)		(Note 2)	(Note 1)	
1	Hearing Costs	171	16	(138)	49	(to Sch 4)
2	Regulatory Enhancement Asset Depreciation and Cost of Debt (Note	(38)	321	-	283	
3	**Total**	**133**	**337**	**(138)**	**332**	

Notes:

Note 1 Positive balance indicates a receivable; negative balance indicates a liability

Note 2 The corresponding expense on Schedule 4 line 14

Note 3 2018 Opening balance has been restated to include opening regulatory asset depreciation and cost of debt variance to filed

Line No.	Line Item Definitions:
1	Hearing costs: costs associated with proceedings for RRT applications that are approved by the Commission.
2	Providers are to add line items for any additional reserve accounts approved by the AUC.

EPCOR Energy Alberta GP Inc.
AFFILIATE TRANSACTIONS
FOR THE YEAR ENDED DECEMBER 31
($000s)

Line No.	Affiliate Name	Nature of Service	2019 Net	2019 Revenue	2019 Expense	2018 Net	Variance higher/(lower)	Variance %		Variance W/P Ref
1	EUI	Administration Allocations	4,916		4,916	4,620	297	6.4%	(to Sch 4)	D
2		Rent & Security	1,681		1,681	1,601	80	5.0%		D
3		Information Technology	1,087		1,087	893	193	21.7%		D
4		Insurance (Note 1)	74		74	85	(11)	-12.9%		
5		Interest on Debt	771		771	375	397	105.8%	(to Sch 5)	D
6		Credit Costs	2,404		2,404	2,069	335	16.2%	(to Sch 4)	D
7		Salary and benefit related costs	16,945		16,945	16,929	16	0.1%		D
8	EWSI	Energy Sales	(12)	12		(11)	(1)	13.5%		
9	Drainage	Energy Sales (Note 1)	(189)	189		(228)	40	-17.5%		
10	EDTI	Energy Sales	(67)	67		(54)	(13)	24.5%		
11		Tariff Charges	176,244		176,244	173,358	2,886	1.7%		D
12		Shared Services	124		124	145	(21)	-14.7%		D
							-			
13	**Total**		**203,979**	**268**	**204,247**	**199,782**				

Note 1 2018 has been restated to include insurance costs and updated energy sales information.

Line No. Line Item Definitions:

1-13 Services with affiliates are not universally defined. Providers are to add line items for any additional transactions with an affiliate.

Column definitions:

2019 Net: sum of 2019 revenue and 2019 expense columns.

2019 Revenue: affiliate transactions that are recorded as a revenue to the RRT provider.

2019 Expense: affiliate transactions that are recorded as an expense to the RRT provider.

2018 Net: sum of prior year affiliate transactions (may be a credit or debit).

Totalling of columns and rows may be influenced by rounding

SCHEDULE 11

EPCOR Energy Alberta GP Inc.

RECONCILIATION FROM AUDITED INCOME STATEMENT TO REGULATORY SCHEDULES

FOR THE YEAR ENDED DECEMBER 31, 2019

($000s)

Line No.	Description	2019 Audited Income Statement	Non RRT Related Adjustments	Regulatory Cost Disallowanc	RRT Portion	
1	**Revenue**	1,045,997			1,045,997	
2	Adjustment for revenue not associated with RRT operations		(106,386)		(106,386)	
3	Total	1,045,997	(106,386)		939,611	(to Sch 2)
4	**Expenses**					
5	Energy and operating expenses	362,689		(927)	361,761	(to Sch 4)
6	Flow through expenses	535,634			535,634	(to Sch 1)
7	Adjustment for expenses not associated with RRT or disallowed	94,392	(94,392)		-	
8	Total	992,715	(94,392)	(927)	897,395	
9	**Depreciation and Amortization**	7,351			7,351	
10	Adjustment for expenses not associated with the RRT or disallowed		(1,777)	(1,319)	(3,096)	
11	Total	7,351	(1,777)	(1,319)	4,254	(to Sch 7)
12	**Interest Expense**	630			630	
13	Adjustment for expenses not associated with the RRT or disallowed		(226)	367	141	
14	Total	630	(226)	367	771	(to Sch 5)
15	**Income/(Loss) before tax**	45,301	(9,990)	1,879	37,189	(to Sch 6)
16	**Income Tax**					
17	Adjustment for expenses not associated with the RRT or disallowed					
18	Total	-	-	-	-	(to Sch 6)
19	**Net Income/(Loss)**	**45,301**	**(9,990)**	**1,879**	**37,189**	(to Sch 1)

Providers are to add line items for any additional adjusting entries if not listed here.

Note: Line 6 reports D&T Energy expenses as expenses for Rule 005 reporting purposes however total revenues reported on the audited financial statements are shown as net of flow-through Energy Expenses.

Rule 005
December 31, 2019
Working Paper A: Energy, Non-Energy, Flow-through Revenues and Expenses and Interest Expense
2019 to 2018 Year-Over-Year Variance Analysis
($000s)

Load and sites provided for information purposes as variance on these items is not significant.

Average Sites		
2018	571,777	from Sch 3 Line 1
2019	557,425	from Sch 3 Line 1
	(14,352)	

Load (GWh)		
2018	4,931	from Sch 3 Line 2
2019	4,700	from Sch 3 Line 2
	(230)	

Variance Explanation: The site count decreased in 2019 from prior year due to attrition of customers from the the RRO to competitive retailers. The load consumption in 2019 decreased due to a decrease in sites counts and decrease in consumption per site as compared to 2018.

Total Energy & Flow-through Revenues as Follows:	**2018**	**2019**	**Variance**	**Ref**
Energy & Final Settlement	315,772	364,262	48,490	(1)
Flow-through	521,708	535,679	13,971	(2)
Non-Energy	36,890	36,132	(758)	(3)
Non-Energy True-Up	(611)	(462)	149	
Total	873,759	935,611	61,853	

(1) Energy Revenues & Final Settlements		**$/MWh**
2018 Energy Revenues	315,772	64.04
2019 Energy Revenues	364,262	77.50
Variance	48,490	

Variance Explanation: The increase in energy revenues is due to an increase in price of $63.3M offset by a decrease in load consumption $(14.8)M.

(2) Flow-through Revenues		**$/MWh**
2018 Flow-through Revenues	521,708	105.81
2019 Flow-through Revenues	535,679	113.97
Variance	13,971	

Variance Explanation: The increase in flow-through revenues is due to an increase in distribution and transmission costs per MWh $38.3M offset by a decrease in load consumption $(24.3)M.

(3) Non-Energy Revenues

2018 Actual	36,279	from Sch 2 Line 3
2017 Non-Energy true-up billed in 2018	611	
2018 adjusted	36,890	
2019 Actual	35,670	from Sch 2 Line 3
2018 Non-Energy true-up billed in 2019	462	
2019 adjusted	36,132	
Variance	(758)	

Variance Explanation: Decrease in non-energy revenue is due to a decrease in sites compared to the prior year.

Revenue Offsets & Other Adjustments

2018 Revenue Offsets & other Adjustments	4,643	from Sch 1 Line 2
2019 Revenue Offsets & other Adjustments	3,999	from Sch 1 Line 2
2018 E-Biill Credit True-up in 2019	407	
2019 adjusted	4,407	
Variance	(237)	

Variance Explanation: Decrease in revenue offsets primarily due to a higher e-bill rate and number of electronic bills in 2019 compared 2018 partially offset by higher late payment charges driven by higher revenues and other small variances.

Interest

2018	375	from Sch 1 Line 5 and Sch 10 Line 4
2019	771	from Sch 1 Line 5 and Sch 10 Line 4
Variance	397	

Variance Explanation: The increase in interest on debt is primarily due to higher working capital requirements due to an increase in lag days.

Total Energy & Flow-through expenses as Follows:	**2018**	**2019**	**Variance**	**Ref**
Energy	310,894	322,120	11,226	(4)
Flow-through	521,857	535,634	13,777	(5)
Total	832,751	857,754	25,003	

(4) Energy Expenses & Final Settlements

2018 Energy Expenses	310,894	from Sch 4 Line 8

2019 Energy Expenses	322,120	from Sch 4 Line 8
Variance	11,226	

Variance Explanation: The increase in energy expense is primarily due to higher AESO energy price $27.4M partially offset by a decrease in load consumption $(12.8)M.

(5) Flow-through Expenses

2018 Flow-through Expenses	521,857	from Sch 1 Line 8
2019 Flow-through Expenses	535,634	from Sch 1 Line 8
Variance	13,777	

Variance Explanation: The increase in flow-through expenses is due to an increase in distribution and transmission costs per MWh $38.2M offset by a decrease in load consumption $(24.4)M.

(6) Interaffiliate Flow-through Expenses

2018 Interaffiliate Flow-through Expenses	173,358	from Sch 10 Line 10
2019 Interaffiliate Flow-through Expenses	176,244	from Sch 10 Line 10
Variance	2,886	

Variance Explanation: The increase in interaffiliate flow-through expenses is due to an increase in distribution and transmission costs per MWh $11.7M offset by a decrease in load consumption $(8.8)M.

Rule 005
December 31, 2019
Working Paper B: Operating Expenses, Depreciation & Income Tax
2019 to 2018 Year-Over-Year Variance Analysis
($000s)

Credit Costs

2018	2,069	from Sch 4 Line 9
2019	2,404	from Sch 4 Line 9
Variance	335	

Variance Explanation: The increase in credit costs is primarily due to backstop credit costs for the new EPSP and an increase standby and placement credit costs.

Interaffiliate Credit Costs

2018	2,069	from Sch 10 Line 5
2019	2,404	from Sch 10 Line 5
Variance	335	

Variance Explanation: All EEA credit costs are interaffiliate and thus the explanation is the same as above.

Billing & Customer Care

2018	24,498	from Sch 4 Line 10
2019	24,333	from Sch 4 Line 10
Variance	(165)	

Variance Explanation: Lower year over year billing and customer care costs are primarily due to higher overhead recoveries and a favourable benefits true-up, partially offset by numerous smaller variances.

Total RRT & Non-RRT Manpower Operating Expense

2018	27,311	from Sch 8 Line 7
2019	28,257	from Sch 8 Line 7
Variance	946	

Total RRT & Non-RRT Manpower FTEs

2018	261.8	from Sch 8 Line 14
2019	286.5	from Sch 8 Line 14
Variance	24.6	

Variance Explanation: Overall payroll costs are increased primarily due to increased full time equivalent requirement related to the CIS project partially offset by a prior period benefits true-up.

Corporate Allocations

2018	4,620	from Sch 4 Line 11
2019	4,916	from Sch 4 Line 11
Variance	297	

Variance Explanation: Increased corporate allocations in 2019 due primarily to EEA's higher head count and consolidated NI share and a higher corporate rent allocation due to higher building operation costs. These increases are partially offset by higher disallowed corporate allocation costs.

Bad Debt Expense

2018	3,604	from Sch 4 Line 13
2019	5,054	from Sch 4 Line 13
Variance	1,450	

Variance Explanation: Increase in bad debt expense primarily driven by increased revenues due to an increase in price and bad debt percentage.

Hearing Costs

2018	(91)	
2019	138	from Sch 4 Line 15
Variance	229	

Variance Explanation: Hearing costs increased in 2019 due to a higher amount recovered compared to 2018 which included refunds related to the 2016-2017 RRT Application.

Income for RRT (before taxes)

2018	1,960	from Sch 6 Line 1
2017 Non-Energy true-up refunded in 2018	611	
2018 adjusted	**2,572**	
2019	35,310	from Sch 6 Line 1
2018 Non-Energy true-up refunded in 2019	462	
2019 adjusted	**35,772**	
Variance	33,201	

Variances Explained

Energy Margin - related to mark to market entries for contracts for differences	21,340
Energy Margin - related to higher risk compensation in 2019	12,552
Energy Margin - related to risk compensation loss in 2018	2,963
Energy Margin - related to lower energy return margin	(1,470)
Energy Margin - related to higher energy development cost for the new EPSP and credit cost recoveries	2,074
Lower Non-Energy Revenues primarily due to lower site counts	(758)
Higher Bad Debt	(1,450)
Higher Interest and credit costs	(732)
Higher Corporate Allocations	(297)
Lower Revenue offsets - related to E-bill credit true-up in 2019 for 2018	(644)
Other	(378)
Total Variances Explained	33,201

Variance Explanation - Energy Margin: [1]Effective July 1, 2011, EEA GP has operated under the Energy Price Setting Plan which resulted in procuring the Energy for its RRT customers through NGX auctions. The contracts entered into during these auctions are contracts for differences. As a result, EEA GP is required to fair value these contracts at each period end date.

[2]The adjusted 2019 gross margin is greater than the 2018 margin primarily due to higher risk compensation. In 2019, EEA switched from a backward looking risk compensation to a new market-derived risk compensation. The increase in risk compensation is in part a recognition of high risk nature of RRT providers' role and due to higher risk aversion required by auction participants. Over time, the risk compensation has started to decrease which reflects a change in the level of the risk aversion of the successful auction participants.

Energy Margin Comparison

	2019	2018	Variance
Gross Margin	42,187	4,728	37,459
Add back costs recorded for future consumption periods[1]	216	10,593	10,377
Bring in costs recorded in prior periods for current consumption[1]	(10,593)	370	10,963
Adjusted Gross Margin[2]	31,810	15,691	16,119

Permanent Differences on Income Tax

2018	(1,960)	from Sch 6 Line 2
2019	(35,310)	from Sch 6 Line 2
Variance	(33,350)	

Variance Explanation: EEA LP is not taxable. The variance is due to an increase in EEA LP's Net Income related to RRT.

Depreciation

2018	4,433	
2019	4,254	From Sch 7 Line 22
Variance	(178)	

Variance Explanation: Decrease in depreciation expense is primarily due to a change in the type of regulatory assets and a lower percentage of costs being allocated to the RRT compared to 2018.

Rule 005
December 31, 2019
Working Paper C: Regulatory Cost Disallowances
2019 to 2018 Year-Over-Year Variance Analysis
($000s)

Regulatory Cost Disallowances		
2018	1,403	
2019	1,879	From Sch 11 Line 19
	476	

Regulatory Cost Disallowance Detail:	**2019**	**2018**	**Var**	**Ref**
Non-Recoverable Corporate Allocations				
Public & Government Affairs	290	189	101	(1)
Short-term Incentive	-	6	(6)	
Mid-term Incentive	94	131	(37)	
Shared Services	63	72	(8)	
Corporate Rent	43	45	(2)	
Total Disallowed Corporate Allocations	491	442	49	
Non-Recoverable Direct Rent Expense	214	223	(9)	
Non-Recoverable EEA GP STIP	-	15	(15)	
Non-Recoverable LTIP/MTIP	50	80	(29)	
Non-Recoverable Long-term Disability	163	(132)	295	(2)
Non-Recoverable Depreciation	1,319	567	752	(3)
Non-Recoverable HCRA	10	40	(31)	
Non-Recoverable Interest Expense	(367)	168	(535)	(4)
Total	**1,879**	**1,403**	**476**	

Notes:

Variance Explanations:

(1) Higher year over year Public & Government affairs allocations to be disallowed due to an increased percentage share of allocated costs to EEA as a result of higher net income, offset by a lower percentage of costs being allocated to the RRT compared to 2018.

(2) Higher year over long-term disability as the 2019 provision adjustment was an expense while 2018 was a refund.

(3) Higher Non-Recoverable Depreciation difference due to accelerated deprecation being booked in IFRS for assets to be replaced by CIS compared to regulatory, loss on disposal and a lower percentage of costs being allocated to the RRT compared to 2018.

(4) Difference due to higher short term interest during 2019 as compared to 2018, resulting in a lower non-recoverable interest expense.

Rule 005
December 31, 2019
Working Paper D: Interaffiliate Transactions
2019 to 2018 Year-Over-Year Variance Analysis
($000s)

Administrative Allocations

2018	4,620	From Sch 10 Line 1
2019	4,916	From Sch 10 Line 1
	297	

Variance Explanation: Increased corporate allocations in 2019 due primarily to EEA's higher head count and consolidated NI share and a higher corproate rent allocation due to higher building operation costs. These increases are offset by higher disallowed corporate allocation costs.

Information Technology

2018	893	From Sch 10 Line 3
2019	1,087	From Sch 10 Line 3
	193	

Variance Explanation: Affiliate information technology expenses higher during 2019 as compared to 2018 due to higher corporate infrastructure charges.

Interaffiliate Credit Costs

2018	2,069	from Sch 10 Line 6
2019	2,404	from Sch 10 Line 6
Variance	335	

Variance Explanation: The increase in credit costs is primarily due to backstop credit costs for the new EPSP and an increase standby and placement credit costs.

Interest on Debt

2018	375	From Sch 10 Line 5
2019	771	From Sch 10 Line 5
	397	

Variance Explanation: The increase in interest on debt is primarily due to higher working capital requirements due to an increase in lag days.

Tariff Charges

2018	173,358	From Sch 10 Line 11
2019	176,244	From Sch 10 Line 11
	2,886	

Variance Explanation: The increase in interaffiliate flow-through expenses is due to an increase in distribution and transmission costs per MWh $11.7M offset by a decrease in load consumption $(8.8)M.

Financial Statements of

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Years ended December 31, 2019 and 2018

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP
Financial Statements

Years ended December 31, 2019 and 2018

KPMG LLP
2200, 10175 – 101 Street
Edmonton, AB T5J 0H3
Telephone (780) 429-7300
Fax (780) 429-7379
www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the General Partner of EPCOR Energy Alberta Limited Partnership

Opinion

We have audited the financial statements of EPCOR Energy Alberta Limited Partnership (the Entity), which comprise:

- the statements of financial position as at December 31, 2019 and December 31, 2018
- the statements of comprehensive income for the years then ended
- the statements of changes in equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2019 and December 31, 2018, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

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

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

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

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

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants

Edmonton, Canada

February 13, 2020

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Comprehensive Income
(In thousands of Canadian dollars)

Years ended December 31, 2019 and 2018

	2019	2018
Revenues (note 5)	$ 474,410	$ 423,620
Operating expenses:		
Electricity purchases	352,348	340,388
Other raw materials and operating charges	233	319
Staff costs and employee benefits expenses	29,535	28,493
Depreciation and amortization (note 6)	7,351	6,423
Other administrative expenses	36,202	32,190
	425,669	407,813
Operating income	48,741	15,807
Finance expenses (note 7)	(3,440)	(3,476)
Comprehensive income for the year - all attributable to the Partners	$ 45,301	$ 12,331

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Financial Position
(In thousands of Canadian dollars)

December 31, 2019 and 2018

	2019	2018
ASSETS		
Current assets:		
Cash (note 8)	$ 4,523	$ 14,485
Trade and other receivables (note 9)	155,895	158,177
	160,418	172,662
Non-current assets:		
Property, plant and equipment (note 10)	1,937	2,119
Intangible assets (note 11)	10,863	15,556
	12,800	17,675
TOTAL ASSETS	$ 173,218	$ 190,337
Current liabilities:		
Trade and other payables (note 12)	$ 107,248	$ 133,950
Loans and borrowings (note 13)	18,194	5,535
Provisions (note 14)	1,117	1,182
Customer deposits	12,253	13,936
Derivative financial instruments (note 15)	109	1,682
	138,921	156,285
Non-current liabilities:		
Loans and borrowings (note 13)	20,000	20,000
Provisions (note 14)	1,819	1,574
	21,819	21,574
Total liabilities	160,740	177,859
Equity attributable to the Partners:		
Partnership units (note 16)	12,478	12,478
Total equity - all attributable to the Partners	12,478	12,478
TOTAL LIABILITIES AND EQUITY	$ 173,218	$ 190,337

Approved on behalf of the EPCOR Board,

Janice G. Rennie
Director, EPCOR Utilities Inc.

Vito Culmone
Director, EPCOR Utilities Inc.

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

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

Years ended December 31, 2019 and 2018

	Partnership units (note 16)	Retained earnings (deficit)	Equity attributable to the Partners
Equity at beginning of January 1, 2018	$ 12,706	$ (228)	$ 12,478
Comprehensive income for the year	-	12,331	12,331
Distribution to Partners	-	(12,103)	(12,103)
Return of Partnership capital	(228)	-	(228)
Equity at December 31, 2018	12,478	-	12,478
Comprehensive income for the year	-	45,301	45,301
Distribution to Partners	-	(45,301)	(45,301)
Equity at December 31, 2019	$ 12,478	$ -	$ 12,478

The accompanying notes are an integral part of these financial statements

EPCOR ENERGY ALBERTA LIMITED PARTNERSHIP

Statements of Cash Flow
(In thousands of Canadian dollars)

Years ended December 31, 2019 and 2018

	2019	2018
Cash flows from (used in) operating activities:		
Comprehensive income for the year	$ 45,301	$ 12,331
Reconciliation of comprehensive income for the year to cash from (used in) operating activities:		
Depreciation and amortization (note 6)	7,351	6,423
Interest paid	(3,440)	(3,476)
Finance expenses (note 7)	3,440	3,476
Changes in employee benefits provisions (note 14)	180	(137)
Changes in customer deposits	(1,683)	335
Changes in fair value of derivative financial instruments (note 15)	(1,573)	2,640
Other	-	(228)
Net cash flows from operating activities before non-cash operating working capital changes	49,576	21,364
Changes in non-cash operating working capital (note 17)	(24,416)	7,467
Net cash flows from operating activities	25,160	28,831
Cash flows from (used in) investing activities:		
Acquisitions of property, plant and equipment[1] (note 10)	(470)	(430)
Acquisitions of intangible assets[1] (note 11)	(2,008)	(1,290)
Proceeds on disposal of property, plant and equipment	2	4
Changes in non-cash investing working capital (note 17)	(4)	29
Net cash flows used in investing activities	(2,480)	(1,687)
Cash flows from (used in) financing activities:		
Net issuance (repayment) of short-term loans and borrowings (note 13)	12,659	(3,996)
Distribution to Partners	(45,301)	(12,103)
Return of Partnership capital	-	(228)
Net cash flows used in financing activities	(32,642)	(16,327)
(Decrease) Increase in cash	(9,962)	10,817
Cash, beginning of year	14,485	3,668
Cash, end of year	$ 4,523	$ 14,485

[1] Interest payments of $13 (2018 - $2) have been capitalized and included in acquisitions of property, plant and equipment (PP&E) and intangible assets.

1. Description of business

(a) Nature of operations

EPCOR Energy Alberta Limited Partnership (the Partnership or EEALP) provides electricity service through its general partner EPCOR Energy Alberta GP Inc. (the General Partner or EEAGP) to regulated rate option (RRO) eligible and default supply customers within the EPCOR Distribution & Transmission Inc. (EDTI) and FortisAlberta Inc. service areas. EEALP provides contact centre and billing and collection services to other EPCOR Utilities Inc. (EPCOR) subsidiaries for water, wastewater, sanitary and stormwater, gas and electricity services, and provides energy procurement services for Encor, EPCOR's competitive retailer. Contact centre, billing and collection services are also provided to The City of Edmonton (the City) Waste Management Department.

The Partnership operates in Canada with its registered head office located at 2000, 10423 – 101 Street NW, Edmonton, Alberta, Canada, T5H 0E8.

EEALP is a limited partnership registered in Canada. The Partnership has one limited partner, EPCOR Power Development Corporation (EPDC), and is managed by EEAGP. Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all the risks and rewards of the assets.

The Partnership is indirectly 100% owned by EPCOR. These financial statements were approved by EPCOR's Board of Directors on behalf the Partnership in accordance with the terms of the partnership agreement.

(b) Rate regulation

The Partnership's operations are regulated by the Alberta Utilities Commission (AUC), pursuant to the *Electric Utilities Act* (Alberta). The AUC administers this act and related regulations regarding tariffs, rates, and service area. The Partnership operates under cost-of-service regulation whereby the AUC issues rate orders establishing the revenue requirement of the business which is the revenue required to recover approved operating costs and to provide a reasonable return. The Partnership applies for non-energy rates based on approved revenue requirement. Once the rates are approved, they are not adjusted as a result of actual costs of service being different from those which were estimated. The Partnership is required to file rate applications with the AUC, for the approval of regulated rate tariff (RRT) electricity billing rates and RRT non-energy revenue billing rates. After a process of public consultation is completed, the AUC approves the rates for the specified period.

The AUC approved the Partnership's 2018-2021 Energy Price Setting Plan ("EPSP") in March 2018 which became effective on April 1, 2019. The current EPSP determines the electricity rates, including electricity margin, and procurement methodology for the Partnership's RRT customers using a market based mechanism to set risk compensation. The AUC approved a combined energy and non-energy return margin structure for the partnership of \$3.28/MWh in 2019 (2018 - \$3.44/MWh).

(c) Rate cap regulation

In November 2016, the Alberta government announced a \$0.068/kWh cap on RRO rates. This rate cap was implemented in June 2017 and was expected to remain in effect until 2021. In December 2019, the legislation was repealed and the rate cap was removed effective November 30, 2019. RRO customers paid the lower of the rate cap or the market-based RRO rate. Pursuant to the rate cap legislation, the government was paying RRO providers for the portion of market rates in excess of the RRO cap. With the exception of the month of March, RRO market rates exceeded the RRO rate cap during all months in 2019. This change in legislation is not considered to have a material effect on the ongoing financial results of the Partnership.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).These financial statements were approved and authorized for issue by the Board of Directors of EPCOR on February 13, 2020.

(b) Basis of measurement

The Partnership's financial statements are prepared on the historical cost basis, except for its derivative financial instruments which are measured at fair value.

(c) Functional and presentation currency

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

3. Significant accounting policies

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

(a) Changes in significant accounting policies

The Partnership adopted IFRS 16 – *Leases* (IFRS 16) and amendments to various accounting standards effective January 1, 2019.The adoption of IFRS 16 and amendments to various accounting standards did not have a significant impact on these financial statements.

(b) Revenue recognition

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

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

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

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

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

Electricity sales

The contracts with customers for the supply of electricity consist primarily of perpetual contracts that are effective until terminated by the customers or the Partnership. Under the terms of the contracts, in case of termination of these contracts, the Partnership has the right to receive payment for the performance completed to the termination date. The Partnership provides a series of distinct goods, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for revenue recognition.

Revenues are calculated based on the customers' usage of the goods during the period, at the applicable rates as per the terms of the respective contracts. Customers are generally billed on a monthly basis and payment is generally due within 21 days of billing the customer.

Provision of services

The Partnership, under contracts with customers for provision of billing, collection and customer care services, provides a series of distinct services, which are simultaneously received and consumed by the customers. Each of the performance obligations is satisfied over time using the output method for revenue recognition, i.e. quantifiable services rendered to the customers. Revenues are calculated based on the services provided to the customers during the period, at the applicable rates as per the terms of the respective contracts. These revenues include an estimate of the value of services provided to the customers in the reporting period and billed subsequent to the reporting period. Customers are billed generally within a month and payment is generally due within 30 days of billing the customer. Under the terms of the contracts, in case of termination of these contracts, the Partnership has the right to receive payment for the performance completed to the termination date.

The Partnership has determined that it is acting as an agent when fulfilling the obligation for collection of distribution and transmission charges on behalf of the distribution companies, as the Partnership does not obtain control of the respective services before they are transferred to the customers. Accordingly, the revenues from the collection of distribution and transmission charges are recognized net of the related costs paid to the distribution companies.

(c) Income taxes

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

(d) Property, plant and equipment

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

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

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

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

The range of estimated useful lives for retail systems and equipment is 3 to 20 years.

Gains or losses on the disposal of PP&E are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

(e) Intangible assets

Intangible assets with finite lives are stated at cost, net of accumulated amortization and impairment losses, if any.

Customer rights represent the costs to acquire the rights to provide electricity services to customers in the FortisAlberta Inc. service territory for a finite period of time. Customer rights are recorded at cost at the date of acquisition. A subsequent expenditure is capitalized only when it increases the future economic benefit in the specific asset to which it relates.

The cost of intangible software includes the cost of license acquisitions, contracted services, materials, direct labor, along with directly attributable overhead costs and borrowing costs on qualifying assets.

Amortization of the cost of finite life intangible assets is recognized on a straight-line basis over the estimated useful lives of the assets, from the date they are available for use, as this most closely reflects the expected usage of the asset. Work in progress is not amortized. The estimated useful lives and methods of amortization are reviewed annually, with any changes adopted on a prospective basis.

The estimated useful lives for intangibles with finite lives are as follows:

Customer rights	20 years
Software	5 - 20 years

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal.

(f) Provisions

A provision is recognized if, as a result of a past event, the Partnership has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance expense over the estimated time period until settlement of the obligation.

(g) Derivative financial instruments

The Partnership uses contracts-for-differences to reduce its exposure to movements in electricity prices. These instruments are used to establish a fixed price for electricity procured primarily to supply RRT customers.

The Partnership sells electricity to customers under a RRT. As part of the RRT, the quantity of electricity to be consumed, the method used to reduce the risk of adverse price movement for the expected electricity consumption and the electricity selling prices to be charged to these customers are determined by an EPSP. The Partnership manages its exposure to fluctuating wholesale electricity spot prices and consumption volume by entering into financial electricity purchase contracts up to 120 days in advance of the month of consumption in order to reduce the risk of adverse price movements of electricity under a well-defined risk management process set out in the EPSP. Under these instruments, the Partnership agrees to exchange, with a counterparty meeting the credit risk parameters of the Partnership, the difference between the Alberta Electric System Operator (AESO) market price and the fixed contract price for a forecasted volume of electricity for the forward months, all in accordance with the EPSP. The Partnership may enter into additional financial electricity purchase contracts outside the EPSP to further mitigate the risk of adverse price movement of electricity.

All derivative financial instruments are recorded at fair value as derivative assets or derivative liabilities on the statement of financial position, to the extent they have not been settled, with all changes in the fair value of derivatives recorded in comprehensive income. At initial recognition, transaction costs attributable to the derivative financial instruments are recognized in comprehensive income.

Fair value is determined based on exchange price quotations in active markets for similar instruments. Fair value amounts reflect management's best estimates using external readily observable market data, such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(h) Non-derivative financial instruments

Financial assets are identified and classified based on the business model used by the Partnership for managing those financial assets, as one of the following: measured at amortized cost or at fair value through profit or loss. Financial liabilities are measured at fair value through profit or loss or at amortized cost.

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

Recognition and measurement

At amortized cost

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

Cash is recognized initially at fair value plus directly attributable transaction costs, if any. Trade and other receivables are recognized initially at their transaction price. After initial recognition, they are measured at amortized cost when they are held for collection of cash flows, where those cash flows solely represent payments of principal and interest using the effective interest method less any impairment as described in note 3(i). The effective interest method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

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

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

At fair value through profit or loss

Financial instruments at fair value through profit or loss include instruments that are designated as financial instruments at fair value through profit or loss or those financial instruments that do not meet the criteria for classification as measured at amortized cost. The Partnership's derivatives instruments are classified at fair value through profit or loss.

Upon initial recognition, directly attributable transaction costs are recognized in comprehensive income as incurred. Changes in fair value of financial instruments measured at fair value through profit or loss are recognized in comprehensive income.

Derecognition

Financial assets are derecognized when the rights to receive cash flows from the financial assets have expired or have been transferred, and the Partnership has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire.

(i) Impairment of financial assets

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

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

(j) Impairment of non-financial assets

The carrying amounts of the Partnership's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E and intangible assets. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists.

The recoverable amount of an asset or cash-generating unit (CGU) is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are tested as a CGU. CGU's are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income.

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

(k) Standards and Interpretations not yet applied

A number of new standards, amendments to standards and interpretations of standards have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee, the application of which is effective for periods beginning on or after January 1, 2020. The Partnership does not expect the implementation of these new accounting pronouncements to have a significant impact on its accounting policies.

4. Use of estimates

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

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

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

Revenues and electricity purchases

Significant accounting estimates were made in determining revenues recognized for unbilled customer consumption. By regulation, electricity wire service providers in Alberta have four months to submit the final electricity load settlement data after the month in which such electricity was consumed. The data and associated processes and systems used by the Partnership to estimate electricity sales revenues and electricity purchase costs, including unbilled consumption, are complex. The Partnership's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

Fair value measurement

Certain accounting measures such as determining asset impairments and recording certain financial and non-financial assets and liabilities require the Partnership to estimate an item's fair value. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

(In thousands of Canadian dollars unless otherwise indicated)

5. Revenues

	2019	2018
Electricity sales[1]	$ 435,804	$ 388,500
Provision of services	38,606	35,120
	$ 474,410	$ 423,620

1 Includes $43,122 (2018 - $21,983) related to amounts recognized as electricity sales in excess of the cap on RRO rates as described in note 1(c).

6. Depreciation and amortization

	2019	2018
Depreciation of property, plant and equipment	$ 650	$ 591
Amortization of intangible assets	6,701	5,519
Loss on disposal of assets	-	313
	$ 7,351	$ 6,423

7. Finance expenses

	2019	2018
Interest on loans and borrowings, net of interest income	$ (745)	$ (1,072)
Guarantee and letters of credit fees	(2,708)	(2,406)
Capitalized interest	13	2
	$ (3,440)	$ (3,476)

8. Cash

Under the agreement between the Partnership and the Natural Gas Exchange (NGX) for the purchase of electricity price forward contracts, the Partnership established separate bank accounts through which the settlement of the electricity price forward contracts are processed in conjunction with letters of credit and cash as collateral. As security for the payment and performance of its obligations, the Partnership assigned a first ranking security interest on the balances of these accounts to NGX. The Partnership's use of this cash is restricted to these purposes. At December 31, 2019 and 2018, all cash was held in these bank accounts.

9. Trade and other receivables

	2019	2018
Trade receivables	$ 77,029	$ 83,188
Accrued revenues	80,496	77,034
Gross accounts receivable	157,525	160,222
Expected credit loss allowance (note 20)	(2,116)	(2,426)
Net accounts receivable	155,409	157,796
Prepaid expenses	486	381
	$ 155,895	$ 158,177

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

(In thousands of Canadian dollars unless otherwise indicated)

10. Property, plant and equipment

	Work in progress	Retail systems & equipment	Total
Cost			
Balance, beginning of 2019	$ -	$ 3,340	$ 3,340
Additions	470	-	470
Disposals and retirements[1]	-	(147)	(147)
Transfers into service	(453)	453	-
Balance, end of 2019	17	3,646	3,663
Accumulated depreciation			
Balance, beginning of 2019	-	1,221	1,221
Depreciation	-	650	650
Disposals and retirements[1]	-	(145)	(145)
Balance, end of 2019	-	1,726	1,726
Net book value, end of 2019	$ 17	$ 1,920	$ 1,937

	Work in progress	Retail systems & equipment	Total
Cost			
Balance, beginning of 2018	$ -	$ 3,599	$ 3,599
Additions	430	-	430
Disposals and retirements[1]	-	(689)	(689)
Transfers into service	(430)	430	-
Balance, end of 2018	-	3,340	3,340
Accumulated depreciation			
Balance, beginning of 2018	-	1,315	1,315
Depreciation	-	591	591
Disposals and retirements[1]	-	(685)	(685)
Balance, end of 2018	-	1,221	1,221
Net book value, end of 2018	$ -	$ 2,119	$ 2,119

1 Gain or loss on disposals is recognized within depreciation and amortization expense.

(In thousands of Canadian dollars unless otherwise indicated)

11. Intangible assets

	Work in progress	Customer rights[1]	Software	Total
Cost				
Balance, beginning of 2019	$ 210	$ 51,228	$ 19,310	$ 70,748
Additions	2,008	-	-	2,008
Disposals and retirements[2]	-	-	(1,652)	(1,652)
Transfers into service	(1,935)	-	1,935	-
Balance, end of 2019	283	51,228	19,593	71,104
Accumulated amortization				
Balance, beginning of 2019	-	46,120	9,072	55,192
Amortization	-	2,554	4,147	6,701
Disposals and retirements[2]	-	-	(1,652)	(1,652)
Balance, end of 2019	-	48,674	11,567	60,241
Net book value, end of 2019	$ 283	$ 2,554	$ 8,026	$ 10,863

	Work in progress	Customer rights[1]	Software	Total
Cost				
Balance, beginning of 2018	$ -	$ 51,228	$ 22,039	$ 73,267
Additions	1,290	-	-	1,290
Disposals and retirements[2]	-	-	(3,809)	(3,809)
Transfers into service	(1,080)	-	1,080	-
Balance, end of 2018	210	51,228	19,310	70,748
Accumulated amortization				
Balance, beginning of 2018	-	43,551	9,618	53,169
Amortization	-	2,569	2,950	5,519
Disposals and retirements[2]	-	-	(3,496)	(3,496)
Balance, end of 2018	-	46,120	9,072	55,192
Net book value, end of 2018	$ 210	$ 5,108	$ 10,238	$ 15,556

1 The partnership's customer rights consist of rights to operate in the FortisAlberta service territory, which will expire on December 31, 2020.

2 Gain or loss on disposals is recognized within depreciation and amortization expense.

12. Trade and other payables

	2019	2018
Trade payables	$ 4,065	$ 33,773
Accrued liabilities	103,183	100,177
	$ 107,248	$ 133,950

(In thousands of Canadian dollars unless otherwise indicated)

13. Loans and borrowings

	2019	2018
Short-term notes payable to EPCOR[1]	$ 18,194	$ 5,535
Long-term notes payable to EPCOR[2]		
At 4.67%, due in 2024	20,000	20,000
Total loans and borrowings	38,194	25,535
Less: current portion	18,194	5,535
	$ 20,000	$ 20,000

1 The short-term notes payable to EPCOR are interest bearing, unsecured and due on demand.
2 The long-term notes payable to EPCOR are unsecured. Interest on notes is payable semi-annually while principal is due at the end of the term.

14. Provisions

	2019	2018
Employee benefits	$ 2,936	$ 2,756
Less: current portion	1,117	1,182
	$ 1,819	$ 1,574

Employee benefits consist mainly of obligations for benefits provided to employees on long-term disability leaves and employee incentive plans.

15. Derivative financial instruments

Derivative financial instruments are electricity price forward contracts, which are held for the purpose of electricity price risk management.

The derivative financial instruments used for risk management purposes as described in note 20 consist of the following:

	2019	2018
Electricity price forward contracts		
Fair value	$ 216	$ 10,593
Cash paid to counterparty	(107)	(8,911)
Net fair value	$ 109	$ 1,682
Net notional buys		
Gigawatt hours of electricity	980	1,238
Range of contract terms (in years)	0.1 - 0.3	0.1 - 0.3

The fair value of electricity price forward contracts reflects changes in the forward electricity prices, net of cash payments to or from the counterparty. During the course of the contracts, daily payments are made to or received from the counterparty to settle the fair value of the contracts.

Fair value is determined based on quoted exchange index prices by reference to bid or asking price, as appropriate, in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

The change in fair value of ($10,377) (2018 – ($10,963)) on unsettled electricity derivative financial instruments is recorded in electricity purchases in the statements of comprehensive income.

(In thousands of Canadian dollars unless otherwise indicated)

16. Partnership Units

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

The General Partner holds one (2018 - one) Class A common unit issued for a capital contribution of $1.00 (2018 - $1.00) in the Partnership. It manages the operations of the Partnership and has a 0.01% (2018 - 0.01%) interest in the profits, losses and capital distributions of the Partnership.

The Limited Partner holds 129,500,999 (2018 - 129,500,999) Class A common units representing a net capital contribution of $12,478 (2018 - $12,478) in the Partnership. The Limited Partner has a 99.99% (2018 - 99.99%) interest in the profits, losses and capital distribution of the Partnership.

17. Change in non-cash working capital

	2019	2018
Trade and other receivables (note 9)	$ 2,282	$ (28,017)
Trade and other payables (note 12)	(26,702)	35,513
	$ (24,420)	$ 7,496
Operating activities	$ (24,416)	$ 7,467
Investing activities	(4)	29
	$ (24,420)	$ 7,496

18. Related party balances and transactions

The Partnership is indirectly 100% owned by EPCOR, which is in turn 100% owned by the City. The Partnership provides electricity, billing, customer care and collection services pursuant to service agreements with EPCOR and its subsidiaries, and the City. EPCOR and its subsidiaries provide services which include administration, maintenance, repairs, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, and safety oversight, human resources and information technology services to the Partnership pursuant to the service agreements. Transactions between the Partnership and its related parties are in the normal course of operations and are generally based on normal commercial rates or as agreed to by the parties.

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

	2019	2018
Statements of Comprehensive Income		
Revenues (a)	$ 28,553	$ 24,713
Electricity purchases (b)	103	125
Staff costs and employee benefits expenses (c)	29,535	28,493
Other administrative expenses and other raw materials	15,408	13,668
Finance expenses (d)	3,338	3,231

(a) Revenues include provision of customer billing services of $26,854 (2018 - $24,011) and electricity sales of $1,699 (2018 - $702). EEALP acts as an agent for distribution and transmission (D&T) charges from distribution companies. During the year, the Partnership incurred D&T charges of $193,760 (2018 – $192,665) from EDTI, which was recorded in revenue net of reimbursements from third party customers.

(b) The 2018 and 2019 figures are comprised of contracts-for-differences expenses.

(c) Staff costs and employee benefit expenses are comprised of $33,660 (2018 - $29,498) of staff costs offset by $4,077 (2018 - $931) of costs transferred to projects outside the Partnership to related parties and $48 (2018 - $74) of costs transferred to projects within the Partnership.

(In thousands of Canadian dollars unless otherwise indicated)

(d) Comprised of fees for providing letters of credit and parental guarantees on behalf of EEALP of $2,708 (2018 - $2,406) and interest on loans and borrowings of $630 (2018 - $825).

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

	2019	2018
Statements of Financial Position		
Trade and other receivables	$ 3,094	$ 2,803
Property, plant and equipment and intangible assets (e)	426	489
Trade and other payables (f)	24,554	21,749
Loans and borrowings (note 13)	38,194	25,535
Provisions (note 14)	2,936	2,756

(e) Relates to expenditures for information services projects.

(f) Comprised of balances payable for D&T services, administration services, interest on loans and borrowings and capital accrual.

The following summarizes the Partnership's related party transactions with the City:

	2019	2018
Statements of Comprehensive Income		
Revenues (g)	$ 4,501	$ 4,267
Other administrative expenses (h)	1,033	1,013

(g) Comprised of commercial services revenue for the provision of customer care services of $4,298 (2018 - $4,102), electricity sales of $102 (2018 - $72), interest earned of $60 (2018 - $44) and other services of $41 (2018 - $49).

(h) Comprised of cash processing fees.

The following summarizes the Partnership's related party balances with the City:

	2019	2018
Statements of Financial Position		
Trade and other receivables	$ 34	$ 493
Trade and other payables	2,103	1,990

19. Financial instruments

Classification

The classification of the Partnership's financial instruments measured at fair value at December 31, 2019 and 2018 are summarized as follows:

	Fair value hierarchy
Derivative financial instruments – designated	Level 1

(In thousands of Canadian dollars unless otherwise indicated)

Fair value

The carrying amounts of all financial instruments measured at amortized cost approximate their fair values due to their short-term nature except for loans and borrowings.

		2019		2018	
	Fair value hierarchy	Carrying amount	Fair value	Carrying amount	Fair value
Loans and borrowings (note 13)	Level 2	$ 38,194	$ 40,369	$ 25,535	$ 27,287

Fair value hierarchy

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

Derivative financial instruments

The fair value of the Partnership's electricity price forward contracts is determined based on exchange index prices in active markets. Fair value amounts reflect management's best estimates using external readily observable market data such as forward electricity prices. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Loans and borrowings

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

The fair value of the Partnership's long-term loans and borrowings is based on determining a current yield for the Partnership's debt at December 31, 2019 and 2018. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Partnership's debt. The estimated credit spread is based on the Partnership's indicative spread as published by independent financial institutions.

20. Financial risk management

Overview

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

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

Market risk

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

To manage the exposure related to changes in market risk related to electricity prices, the Partnership uses contracts-for-differences as a risk management technique. These instruments are used to establish a fixed price for electricity purchases.

The sensitivities provided in the following risk discussions disclose the effect of reasonable changes in relevant prices and rates on comprehensive income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Partnership's actual exposure to market risk is constantly changing as the Partnership's portfolio of commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Partnership.

Electricity price and volume risk

The Partnership sells electricity to RRO customers under a RRT. All electricity for the RRO customers is purchased in real time from the AESO in the spot market. Under the RRT, the quantity of electricity consumption, method used to reduce the risk of adverse price movement for the expected electricity consumption, and the electricity selling prices to be charged to these customers are determined by the EPSP. Under the EPSP, the Partnership uses financial contracts to mitigate the risk of adverse price movement of electricity under the RRO requirements and incorporate the price into customer rates for the applicable month. The Partnership enters into financial contracts-for-difference for forecasted volumes of electricity to mitigate the risk of adverse price movement up to 120 days in advance of the month in which the electricity (load) is expected to be consumed by the RRO customers. The volume of electricity is based on load (usage) forecasts for the consumption month. When consumption varies from forecast consumption patterns, the Partnership is exposed to prevailing market prices on fifty percent of the load when the volume of electricity contracted under the financial contracts-for-differences is short of actual load requirements or greater than the actual load requirements (long). Exposure to variances in electricity volume can be exacerbated by other events such as unexpected generation plant outages and extreme weather patterns.

Under contracts-for-differences the Partnership agrees to exchange, with a counterparty meeting the credit risk parameters of the Partnership, the difference between the AESO electricity spot market price and the fixed contract price for a forecasted volume of electricity up to 120 days in advance of the consumption date, all in accordance with the EPSP. The contracts-for-differences are referenced to the AESO electricity spot price and any movement in the AESO price results in changes in the contract settlement amount. If the risks of the EPSP were to become untenable, the Partnership could test the market and potentially re-contract the procurement risk under an outsourcing arrangement at a certain cost that would likely increase procurement costs and reduce margins. The Partnership may enter into additional financial electricity purchase contracts outside the EPSP to further mitigate the risk of adverse movement in the price of electricity.

At December 31, 2019, holding all other variables constant, a $5 per megawatt hour increase or decrease in the forward electricity spot price would increase or decrease comprehensive income by approximately $4,901 (2018 - $6,189). In preparing the sensitivity analysis, the Partnership compared average AESO electricity spot prices to the forward index price for the past 24 months. Based on historical fluctuations, the Partnership estimates that the fair value of the contracts could increase or decrease by up to $20,736 (2018 - $16,089) with a corresponding change to comprehensive income.

Interest rate risk

The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. Interest rate risk associated with short-term loans and borrowings is immaterial due to its short-term maturity. At December 31, 2019 and 2018, all long-term debt was fixed rate.

(In thousands of Canadian dollars unless otherwise indicated)

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. EPCOR's credit risk management policy is approved by the Board of Directors of EPCOR and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the group including the Partnership. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to senior management. In its role as the default electricity provider for its service territories, the Partnership must provide service to customers who choose to receive regulated electricity service. Amounts owing from customers are monitored and are regularly reported to senior management. Creditworthiness continues to be evaluated after transactions have been initiated, at a minimum, on an annual basis. To manage and mitigate credit risk, the Partnership employs various credit mitigation practices such as cash deposits, parent company guarantees and bank letters of credit.

Maximum credit risk exposure

The Partnership's maximum credit exposure is represented by the carrying amount of the trade and other receivables balance of $155,409 (2018 - $157,796) (note 9). These carrying amounts do not take into account collateral held. At December 31, 2019, the Partnership held cash deposits of $12,253 (2018 - $13,936) as security for certain counterparty accounts receivable.

Credit quality and concentrations

The Partnership is exposed to credit risk on outstanding trade receivables associated with its electricity sales to retail customers. The Partnership is also exposed to credit risk from its cash and derivative assets.

The credit quality of the Partnership's cash and trade and other receivables, as at December 31, 2019 and 2018, was the following:

	2019		2018	
	Investment grade or secured[1,2]	Unrated	Investment grade or secured[1,2]	Unrated
	%	%	%	%
Cash	100	-	100	-
Trade and other receivables	10	90	11	89

1 Credit ratings are based on the Partnership's internal criteria and analyses, which take into account, among other factors, the investment grade ratings of external credit rating agencies when available.
2 Certain trade and other receivables are considered to have low credit risk as they are either secured by the underlying assets, secured by other forms of credit enhancements, or the counterparties are EPCOR and its subsidiaries as well as local or provincial governments.

Rate-regulated customer credit risk

Credit risk exposure for residential and commercial customers under default electricity and regulated electricity supply rates is generally limited to amounts due from customers for electricity consumed but not yet paid for. The Partnership mitigates credit risk from counterparties under RRT electricity supply rates by performing credit checks and on higher risk customers, by taking cash deposits. The Partnership monitors credit risk for this portfolio at the gross exposure level.

Trade and other receivables and expected credit loss allowance

Trade and other receivables consist primarily of amounts due from retail customers including residential and commercial customers. Commercial customers provide performance assurances through letters of credit, irrevocable guarantees and bonds. For retail customers, represented by a diversified customer base, credit losses are generally low and the Partnership provides for an allowance for lifetime ECL.

(In thousands of Canadian dollars unless otherwise indicated)

The Partnership calculates the ECL allowance on accounts receivable using a provision matrix approach, which is based on the Partnership's historical credit loss experience and current economic conditions (including forward-looking information) for accounts receivable. The provision matrix specifies fixed provision rates depending on the number of days that a trade receivable is due or past due. The total ECL allowance at December 31, 2019 was $2,116 (2018 - $2,426).

The gross accounts receivable and analysis of the changes in the ECL allowance was as follows:

December 31, 2019	Gross accounts receivables	Expected credit loss allowance	Net accounts receivables
Current[1]	$ 143,228	$ 511	$ 142,717
Outstanding 31 to 60 days	9,960	321	9,639
Outstanding 61 to 90 days	2,358	239	2,119
Outstanding more than 90 days	1,979	1,045	934
	$ 157,525	$ 2,116	$ 155,409

December 31, 2018	Gross accounts receivables	Expected credit loss allowance	Net accounts receivables
Current[1]	$ 145,682	$ 641	$ 145,041
Outstanding 31 to 60 days	9,194	298	8,896
Outstanding 61 to 90 days	2,848	287	2,561
Outstanding more than 90 days	2,498	1,200	1,298
	$ 160,222	$ 2,426	$ 157,796

1 Current amounts represent trade and other receivables outstanding up to 30 days. Amounts outstanding for more than 30 days are considered past due.

The changes in the ECL allowance were as follows:

	2019	2018
Balance, beginning of year	$ 2,426	$ 2,110
Additional allowances created	7,361	6,104
Recovery of receivables	2,711	1,461
Receivables written off	(10,382)	(7,249)
Balance, end of year	$ 2,116	$ 2,426

During the year, the Partnership recognized $7,361 (2018 - $6,104) ECL as an expense within comprehensive income relating to customer amounts that the Partnership determined may not be fully collectable. The ECL allowance is determined by considering the unique factors of different customer types. Write-offs are determined by applying specific risk factors to customer groups' aged balances in trade and other receivables or by reviewing material accounts on a case-by-case basis. Reductions in trade and other receivables and the related ECL allowance are recorded when the Partnership has determined that recovery is not possible.

At December 31, 2019, the Partnership held $12,253 (2018 - $13,936) of customer deposits for the purpose of mitigating the credit risk associated with trade and other receivables from residential and commercial customers.

Liquidity risk

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

(In thousands of Canadian dollars unless otherwise indicated)

The undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments at December 31, 2019, are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total contractual cash flows
Trade and other payables[1]	$106,929	$ -	$ -	$ -	$ -	$ -	$ 106,929
Loans and borrowings	18,194	-	-	-	20,000	-	38,194
Interest payments on loans and borrowings	933	933	933	933	614	-	4,346
Customer deposits	12,253	-	-	-	-	-	12,253
	$138,309	$ 933	$ 933	$ 933	$ 20,614	$ -	$ 161,722

1 Excluding accrued interest on loans and borrowings of $319 (2018 - $319).

The Partnership's undiscounted cash flow requirements and contractual maturities in the next twelve months of $138,309 will be funded from operating cash flows.

21. Capital management

The Partnership's primary objectives when managing capital are to safeguard the Partnership's ability to continue as a going concern, pay cash distributions to its unit holders, and to maintain a suitable credit rating. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with AUC regulatory decisions. This overall objective and policy for managing capital remained unchanged in the current year from the prior year.

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

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

	2019	2018
Loans and borrowings (including current portion) (note 13)	$ 38,194	$ 25,535
Total equity	12,478	12,478
Total capital	$ 50,672	$ 38,013

For the years ended December 31, 2019 and 2018, the Partnership complied with all externally imposed capital restrictions.

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

22. Commitments and contingencies

The following are the Partnership's commitments and contingencies not otherwise disclosed in these financial statements:

(a) The Partnership has signed an eight year agreement with FortisAlberta Inc. to provide RRO and Default Supply Services following the expiration of the current agreement December 31, 2020 for and estimated $50,120, which will be paid in 2020. The agreement has been approved by the AUC December 9, 2019.

(b) Commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $14,159 (2018 - $14,184). These estimates are subject to change based on actual activity levels.

(c) The Partnership is committed to pay interest and fees to EPCOR for providing letters of credit, parental guarantees and cash collateral on its behalf to EDTI, FortisAlberta Inc., AESO and NGX. The fees charged to EEALP for the letters of credit and parental guarantees are based on the total value outstanding of $131,800 (2018 - $127,650). The letters of credit expire on various dates in 2020. All letters of credit renew automatically.

(d) The Partnership is subject to various legal claims that may arise in the normal course of business. Management believes that the aggregate contingent liability of the Partnership arising from these claims is immaterial and therefore no provision has been made.