Test Year Ending June 30, 2018

			Total Company		Kansas			
Line No.	Revenue Class	Reference	Pro Forma Operating Revenue	Reference	Pro Forma Operating Revenue	Reference	Proposed Increase	After Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	Section 8	$ 266,511,967	Section 17	$ 9,618,055	(g) Line 11x ((e) Line1/(e) Line 11)	$ 876,984	$ 10,495,039
2	Commercial	Section 8	185,854,262	Section 17	2,213,843	(g) Line 11x ((e) Line2/(e) Line 11)	201,860	2,415,703
3	Industrial	Section 8	93,999,760	Section 17	6,065,268	(g) Line 11x ((e) Line3/(e) Line 11)	553,037	6,618,305
4	Street & Highway Lighting	Section 8	4,257,545	Section 17	636,306	(g) Line 11x ((e) Line 4/(e) Line 11)	58,019	694,325
5	Public Authorities	Section 8	11,793,735		-		-	-
6	Interdepartmental	Section 8	335,631		-		-	-
7	Sales for Resale On-System	Section 8	20,120,325		-		-	-
8	Sales for Resale Off-System	Section 8	35,919,250		-		-	-
9	Total Sales of Electricity		618,792,475		18,533,472	Section 3	1,689,900	20,223,372
10	Other Electric Operating Revenue	Section 8	12,502,471		-			
11	Total Electric Operating Revenue		$ 631,294,945		$ 18,533,472		$ 1,689,900	$ 20,223,372

* Allocated on Basis of Common Transmission Plant

Communities Affected

Incorporated:

Baxter Springs
Columbus
Galena
West Mineral
Roseland
Scammon
Weir

Unincorporated:

Camp 42
Carona
Hallowell
Lowell
Melrose
Riverton
Treece

Test Year Ending June 30, 2018										
					Total Company	**Kansas**				
Line No.	**Revenue Class**	**Reference**	**Average Customers**	**Reference**	**Pro Forma Operating Revenue**	**Reference**	**Pro Forma Before Increase**	**Reference**	**Proposed Increase**	**Monthly Average Increase Per Customer**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Revenue Class**									
2	Residential	Section 17	8,173	Section 8	$266,511,967	WP-2 Col c Line 1	$ 9,618,055	WP-2 Col d Line 1	$ 876,984	$9
3	Commercial	Section 17	1,294	Section 8	185,854,262	WP-2 Col c Line 2	2,213,843	WP-2 Col d Line 2	201,860	$13
4	Industrial	Section 17	150	Section 8	93,999,760	WP-2 Col c Line 3	6,065,268	WP-2 Col d Line 3	553,037	$307
5	Street & Highway Lighting	Section 17	51	Section 8	4,257,545	WP-2 Col c Line 4	636,306	WP-2 Col d Line 4	58,019	$95
6	Public Authorities		-	Section 8	11,793,735	WP-2 Col c Line 5	-	WP-2 Col d Line 5	-	-
7	Interdepartmental		-	Section 8	335,631	WP-2 Col c Line 6	-	WP-2 Col d Line 6	-	-
8	Sales for Resale On-System		-	Section 8	20,120,325	WP-2 Col c Line 7	-	WP-2 Col d Line 7	-	-
9	Sales for Resale Off-System		-	Section 8	35,919,250	WP-2 Col c Line 8	-	WP-2 Col d Line 8	-	-
10	Total Cust / Sales of Electricity		9,668		618,792,475		18,533,472		1,689,900	424
11	Other Electric Operating Revenue		-	Section 8	12,502,471	WP-2 Col c Line 10	-	WP-2 Col d Line 10	-	-
12	Total Electric Operating Revenue				$631,294,945		$18,533,472		$1,689,900	$424

* Annual Average Increase for Lighting

Summary of Reasons for Filing Application for Rate Increase

Line No.	Rate Relief Description
1	Current base rates became effective Janaury 1, 2012.
2	Asbury Environmental and Riverton Rider (AERR) Rider Capital to be included in base rates at next rate case.
3	Other capital investments since 2011.
4	Tax Reform Stipulation and Agreement.
5	Increased operating expenses.

Test Year Ending June 30, 2018

			Kansas			
Line No.	**Revenue Class**	**Reference**	**Pro Forma Operating Revenue**	**Reference**	**Proposed Increase**	**After Increase**
	(a)	(b)	(c)	(d)	(e)	(f)
1	Residential	Section 17	$ 1,817,562	(g) Line 11x ((e) Line1/(e) Line 11)	$ 970,039	$ 2,787,601
2	Commercial	Section 17	299,428	(g) Line 11x ((e) Line2/(e) Line 11)	159,806	459,234
3	Industrial	Section 17	1,040,566	(g) Line 11x ((e) Line3/(e) Line 11)	555,354	1,595,920
4	Street & Highway Lighting	Section 17	8,810	(g) Line 11x ((e) Line 4/(e) Line 11)	4,702	13,512
5	Public Authorities		-		-	-
6	Interdepartmental		-		-	-
7	Sales for Resale On-System		-		-	-
8	Sales for Resale Off-System		-		-	-
9	Total Sales of Electricity		3,166,367	Section 3	1,689,900	4,856,267
10	Other Electric Operating Revenue		-			
11	Total Electric Operating Revenue		$ 3,166,367		$ 1,689,900	$ 4,856,267

* Allocated on Basis of Common Transmission Plant

Communities Affected

Incorporated:

- Baxter Springs
- Columbus
- Galena
- West Mineral
- Roseland
- Scammon
- Weir

Unincorporated:

- Camp 42
- Carona
- Hallowell
- Lowell
- Melrose
- Riverton
- Treece

Test Year Ending June 30, 2018

		Kansas						
Line No.	Revenue Class	Reference	Average Customers	Reference	Pro Forma Before Increase	Reference	Proposed Increase	Monthly Average Increase Per Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Revenue Class**							
2	Residential	Section 17	8,173	WP-2 Col c Line 1	$ 1,817,562	WP-2 Col d Line 1	$ 970,039	$10
3	Commercial	Section 17	1,294	WP-2 Col c Line 2	299,428	WP-2 Col d Line 2	159,806	10
4	Industrial	Section 17	150	WP-2 Col c Line 3	1,040,566	WP-2 Col d Line 3	555,354	309
5	Street & Highway Lighting	Section 17	51	WP-2 Col c Line 4	8,810	WP-2 Col d Line 4	4,702	8
6	Public Authorities		-	WP-2 Col c Line 5	-	WP-2 Col d Line 5	-	-
7	Interdepartmental		-	WP-2 Col c Line 6	-	WP-2 Col d Line 6	-	-
8	Sales for Resale On-System		-	WP-2 Col c Line 7	-	WP-2 Col d Line 7	-	-
9	Sales for Resale Off-System		-	WP-2 Col c Line 8	-	WP-2 Col d Line 8	-	-
10	Total Cust / Sales of Electricity		9,668		3,166,367		1,689,900	336
11	Other Electric Operating Revenue		-	WP-2 Col c Line 10	-	WP-2 Col d Line 10	-	-
12	Total Electric Operating Revenue				$3,166,367		$1,689,900	$336

* Annual Average Increase for Lighting

Summary of Reasons for Filing Application for Rate Increase

Line No.	Rate Relief Description
1	Current base rates became effective Janaury 1, 2012.
2	Asbury Environmental and Riverton Rider (AERR) Rider Capital to be included in base rates at next rate case.
3	Other capital investments since 2011.
4	Tax Reform Stipulation and Agreement.
5	Increased operating expenses.

Test Year Ending June 30, 2018

Line No.	Description	Reference	Kansas Jurisdiction Ending Balance	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	Rate Base	WP-3.1 Rate Base	$ 78,384,925	$ (14,611,575)	$ 63,773,350
2	Revenues	WP-3 Operate Income, Line 4 Column (f)	26,111,192	(9,267,619)	16,843,573
3	Expenses	WP-3 Operate Income, Line 17 Column (f)	19,670,492	(6,838,768)	12,831,724
4	Net Operating (Loss) Before Taxes	Line 2 - Line 3	6,440,699	(2,428,851)	4,011,848
5	State Income Tax	WP-3 Operate Income, Line 19 Column (f)	187,846	(26,126)	161,720
6	Federal Income tax	WP-3 Operate Income, Line 20 Column (f)	1,749,341	(1,458,009)	291,333
7	Net Operating Income (Loss) After Taxes	Line 4 - Line 5 - Line 6	4,503,512	(944,716)	3,558,796
8	Current Rate of Return	(Line 7 / Line 1)	5.75%		5.58%
9	Rate of Return Requested	WP-3 Rate of Return	7.54%		7.54%
10	Required Net Operating Income	(Line 9 x Line 1)	5,911,511	-	4,809,558
11	Income Deficiency	(Line 10 - Line 7)	1,407,999	944,716	1,250,763
12	Gross Revenue Conversion factor	WP-3 GRCF	1.3511	1.3511	1.3511
13	Revenue Deficiency	(Line 11 x Line 12)	1,902,342	1,276,402	1,689,900
14	Revenue Deficiency %	(Line 13 / Line 2)	7.29%	-13.77%	10.03%
15	Revenue Requirement	(Line 2 + Line 13)	$ 28,013,533	$ (7,991,216)	$ 18,533,473

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company Ending Balance	Total Company Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Kansas Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Electric Plant in Service	WP-4 Plant in Service	$ 2,818,371,221	$ 2,509,369	$ 2,820,880,590	$ 141,340,858	$ (18,018,017)	$ 123,322,841
2	Less: Accumulated Depreciation	WP-5 Accum Depr	(960,856,266)	-	(960,856,266)	(47,363,690)	5,259,623	(42,104,067)
3	Net Plant in Service	Line 1 + Line 2	1,857,514,955	2,509,369	1,860,024,324	93,977,168	(12,758,394)	81,218,774
4	Accumulated Deferred Income Taxes	WP-3.2 ADIT	(246,233,175)	(31,732,536)	(277,965,711)	(14,308,436)	1,910,258	(12,398,178)
5	Customer Advances	WP-6.3 Cust Adv & Dep	(3,336,478)	560,071	(2,776,407)	(16,333)	-	(16,333)
6	Customer Deposits	WP-6.3 Cust Adv & Dep	(14,294,447)	441,271	(13,853,176)	(431,012)	(5,984)	(436,996)
9	Prepaid Expenses	WP-6.1 Prepayments	8,151,213	(450,476)	7,700,737	408,782	(23,584)	385,198
10	Material & Supplies	WP-6.2 Materials & Supplies	54,285,510	(4,596,750)	49,688,760	2,723,117	(234,571)	2,488,546
11	Regulatory Asset	WP 3.1 Reg Asset & Liab	205,635,975	(52,364,090)	153,271,885	4,392,625	(4,392,625)	-
12	Regulatory Liability	WP 3.1 Reg Asset & Liab	(328,945,867)	156,340,064	(172,605,803)	(8,510,504)	917,717	(7,592,787)
13	Allowance for Cash Working Capital	WP 6.6 Cash Working Capital	149,410	(24,393)	125,017	149,519	(24,393)	125,126
14	Total Rate Base	Sum of Line 3 through Line 13	$ 1,532,927,096	$ 70,682,530	$ 1,603,609,626	$ 78,384,925	$ (14,611,575)	$ 63,773,350

Test Year Ending June 30, 2018

		Kansas									
Line No.	**Description**	**Iatan and Plum Point Prudency**	**13 Month Average Adjustment**	**Water Inventory Adjustment**	**CWIP Adjustment**	**Common Property Gas**	**TDC Adjustment**	**Regulatory Asset Adjustment**	**Regulatory Liability Adjustment**	**Merit Increase**	**Total Kansas Pro Forma Adjustments**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k) = SUM (b) through (j)
1	**Adjustment Number**	**ADJ-1**	**Section 6.3 Cust Adv & Dep, ADJ-21, ADJ-22**	**ADJ-4**	**ADJ-5**	**ADJ-2**	**ADJ-17**	**ADJ-3**	**ADJ-3**	**ADJ-16**	
2	Electric Plant in Service	$ (59,404)	$ -	$ -	$ 259,487	$ (109,200)	$ (18,128,851)	$ -	$ -	$ 19,951	$ (18,018,017)
3	Less: Accumulated Depreciation	7,488			(9,872)	68,435	5,194,205			(632)	5,259,623
4	Net Plant in Service (Line 1 + Line 3)	(51,916)	-	-	249,615	(40,765)	(12,934,646)	-	-	19,319	(12,758,394)
5	Accumulated Deferred Income Taxes				(622)		1,910,880				1,910,258
6	Customer Advances		-								-
7	Customer Deposits		(5,984)								(5,984)
8	Material & Supplies		(86,898)	(2,695)			(144,978)				(234,571)
9	Prepaid Expenses		40,780				(64,364)				(23,584)
10	Regulatory Asset							(4,392,625)			(4,392,625)
11	Regulatory Liability								917,717		917,717
12	Allowance for Cash Working Capital						(24,393)				(24,393)
13	Total Rate Base (Sum of Line 4 through Line 12)	$ (51,916)	$ (52,102)	$ (2,695)	$ 248,993	$ (40,765)	$ (11,257,501)	$ (4,392,625)	$ 917,717	$ 19,319	$ (14,611,575)

Test Year Ending June 30, 2018

			Total Company			Kansas		
Line No.	Description	Reference	Ending Balance	Pro Forma Adjustments	As Adjusted Under Present Rates	Ending Balance	Pro Forma Adjustments	As Adjusted Under Present Rates
	(a)	(b)	(c)	(d)	(e)= (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Electric Utility Operating Revenues:							
2	Electric Service Revenue	Section 9	$ 618,792,475	$ (9,267,619)	$ 609,524,856	$ 26,168,113	$ (9,267,619)	$ 16,900,494
3	Other Electric Operating Revenues	Section 9	12,502,471		12,502,471	(56,921)		(56,921)
4	Total Electric Utility Operating Revenue		631,294,945	(9,267,619)	622,027,327	26,111,192	(9,267,619)	16,843,573
5	Electric Utility Operating Expenses:							
6	Production	Section 9	206,647,698	(5,829,564)	200,818,134	8,672,796	(5,829,564)	2,843,232
7	Transmission	Section 9	25,075,914	(1,224,251)	23,851,663	1,224,251	(1,224,251)	-
8	Distribution	Section 9	25,438,528	26,445	25,464,973	1,499,028	26,445	1,525,473
9	Customer Account Expense	Section 9	8,754,321	49,312	8,803,633	490,707	49,312	540,019
10	Customer Assistance	Section 9	4,144,157	5,372	4,149,529	87,232	5,372	92,603
11	Sales Expenses	Section 9	153,719	378	154,097	6,605	378	6,983
12	Administrative & General Expenses	Section 9	1,321,445	125,423	1,446,868	103,350	125,423	228,773
13	Other Administrative & General Expenses	Section 9	50,545,875	373,849	50,919,724	1,960,202	373,849	2,334,051
14	Depreciation & Amortization Expense	Section 9	80,344,732	259,763	80,604,495	3,885,270	259,763	4,145,032
15	Taxes other than Income	Section 9	36,469,544	(632,555)	35,836,989	1,741,052	(632,555)	1,108,497
16	Interest on Customer Deposits	Section 9		7,062	7,062		7,062	7,062
17	Total Electric Utility Operating Expense		438,895,933	(6,838,768)	432,057,165	19,670,492	(6,838,768)	12,831,724
18	Net Operating Income (Loss) Before Taxes	Line 4 - Line 17	192,399,013	(2,428,851)	189,970,161	6,440,699	(2,428,851)	4,011,848
19	State Income Taxes	Section 9	5,762,100	4,499,427	10,261,527	187,846	(26,126)	161,720
20	Federal Income Taxes	Section 9	58,437,989	(26,449,557)	31,988,432	1,749,341	(1,458,009)	291,333
21	Total Taxes		64,200,089	(21,950,130)	42,249,959	1,937,187	(1,484,135)	453,053
22	Net Operating Income After Taxes	Line 18 - Line 21	$ 128,198,924	$ 19,521,279	$ 147,720,202	$ 4,503,512	$ (944,716)	$ 3,558,796

Test Year Ending June 30, 2018

Line No.	Description	Weather Norm Revenue Adjustment 2018	Unbilled Revenue	Revenue Adjustment Franchise Fee	Revenue Adjustment Ad Valorem Tax Surcharge Rider	Customer Deposit Int. Exp. Adj.	Revenue Adjustment Asbury Riverton Environmental Rider (AERR)	Revenue Adjustment Fuel ECA
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Adjustment Number**	**ADJ-13**	**ADJ-27**	**ADJ-26**	**ADJ-24**	**Section 12**	**ADJ-25**	**ADJ-23**
2	Revenues	$ (195,088)	$ (160,692)	$ (471,195)	$ (555,293)	$ -	$ (1,794,980)	$ (5,119,783)
3	Production							
4	Transmission Expenses							
5	Distribution Expenses							
6	Customer Account Expense							
7	Customer Service & Informational Expense							
8	Sales Expenses							
9	Administrative & General Expenses							
10	Other Administrative & General Expenses							
11	Depreciation & Amortization Expense							
12	Taxes other than Income							
13	Interest on Customer Deposit					7,062		
14	Total Operating & Maintenace Expenses (Sum of Line 3 through Line 13)	-	-	-	-	7,062	-	-
15	Income Tax							
16	Net Operating Income (Loss) Before Taxes (Line 2 - Line 14 - Line 15)	$ (195,088)	$ (160,692)	$ (471,195)	$ (555,293)	$ (7,062)	$ (1,794,980)	$ (5,119,783)

Test Year Ending June 30, 2018

Line No.	Description	Merit Increase	Plum Point Contract Update	Fuel ECA	TDC Adjustment	Uncollectible Exp. Adj.	Rate Case Expense Adjustment	Pension and OPEB Adjustment
	(a)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Adjustment Number**	**ADJ-16**	**ADJ-14**	**ADJ-15**	**ADJ-17**	**ADJ-8**	**ADJ-7**	**ADJ-18**
2	Revenues	$ -	$ -	$ (1,507,495)	$ (53,808)	$ -	$ -	$ -
3	Production	18,928	12,488	(5,885,048)	(14,492)			
4	Transmission Expenses				(1,224,251)			
5	Distribution Expenses	11,329						
6	Customer Account Expense	6,002				31,082		
7	Customer Service & Informational Expense	1,769						
8	Sales Expenses	124						
9	Administrative & General Expenses						213,730	
10	Other Administrative & General Expenses	14,073			(212,605)			653,136
11	Depreciation & Amortization Expense	632						
12	Taxes other than Income	4,689			(168,185)			
13	Interest on Customer Deposit							
14	Total Operating & Maintenace Expenses (Sum of Line 3 through Line 13)	57,547	12,488	(5,885,048)	(1,619,534)	31,082	213,730	653,136
15	Income Tax							
16	Net Operating Income (Loss) Before Taxes (Line 2 - Line 14 - Line 15)	$ (57,547)	$ (12,488)	$ 4,377,553	$ 1,565,726	$ (31,082)	$ (213,730)	$ (653,136)

Test Year Ending June 30, 2018

Line No.	Description	Annualized Depreciation Adjustment	Medical, Dental & Vision Expense	Franchise Tax Adjustment	Open Positions	Overtime Adjustment	Non Deductible Expense
	(a)	(p)	(q)	(r)	(s)	(t)	(u)
1	**Adjustment Number**	**See Section 10**	**ADJ-12**	**See Section 11**	**ADJ-9**	**ADJ-28**	**ADJ-19**
2	Revenues	$ -	$ -	$ -	$ -	$ -	$ -
3	Production				34,520	4,040	(1)
4	Transmission Expenses						
5	Distribution Expenses				20,661	2,418	(24)
6	Customer Account Expense				10,947	1,281	
7	Customer Service & Informational Expense				3,226	377	
8	Sales Expenses				227	27	
9	Administrative & General Expenses						
10	Other Administrative & General Expenses		139,838		25,665	3,003	(250)
11	Depreciation & Amortization Expense	250,291					
12	Taxes other than Income			(471,290)			
13	Interest on Customer Deposit						
14	Total Operating & Maintenace Expenses (Sum of Line 3 through Line 13)	250,291	139,838	(471,290)	95,246	11,146	(275)
15	Income Tax						
16	Net Operating Income (Loss) Before Taxes (Line 2 - Line 14 - Line 15)	$ (250,291)	$ (139,838)	$ 471,290	$ (95,246)	$ (11,146)	$ 275

		Test Year Ending June 30, 2018							
Line No.	**Description**	**Federal Income Tax Adjustment**	**State Income Tax Adjustment**	**CWIP Adjustment**	**Iatan & Plum Point Prudency**	**Tax Reform Rev. Adj.**	**A&G Expense Adjustment**	**Prior Rate Case Amort. Overage Adj.**	**Total Kansas Pro Forma Adjustment**
	(a)	(v)	(w)	(x)	(y)	(z)	(aa)	(bb)	(cc) = SUM (b) through (bb)
1	**Adjustment Number**	**See Section 11**	**See Section 11**	**ADJ-5**	**ADJ-1**	**ADJ-3**	**ADJ-6**	**ADJ-10**	
2	Revenues	$ -	$ -	$ -	$ -	$ 590,715	$ -	$ -	$ (9,267,619)
3	Production								(5,829,564)
4	Transmission Expenses								(1,224,251)
5	Distribution Expenses							(7,939)	26,445
6	Customer Account Expense								49,312
7	Customer Service & Informational Expense								5,372
8	Sales Expenses								378
9	Administrative & General Expenses							(88,307)	125,423
10	Other Administrative & General Expenses						(249,011)		373,849
11	Depreciation & Amortization Expense			9,872	(1,033)				259,763
12	Taxes other than Income			2,894	(663)				(632,555)
13	Interest on Customer Deposit								7,062
14	Total Operating & Maintenace Expenses (Sum of Line 3 through Line 13)	-	-	12,766	(1,695)	-	(249,011)	(96,246)	(6,838,768)
15	Income Tax	(1,458,009)	(26,126)						(1,484,135)
16	Net Operating Income (Loss) Before Taxes (Line 2 - Line 14 - Line 15)	$ 1,458,009	$ 26,126	$ (12,766)	$ 1,695	$ 590,715	$ 249,011	$ 96,246	$ (944,716)

Test Year Ending June 30, 2018

Line No.	Description	Reference	Kansas Adjusted Federal	Kansas Adjusted State	Kansas Total Taxes
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	Net Operating Income Before Tax	WP-3 Operating Income	$ 4,011,848	$ 4,011,848	
2	Effective Tax Rates	WP-3 GRCF Column (c), Line 1 & 3	19.67%	6.31%	
3	Tax - Subtotal	Line 1 x Line 2	789,315	253,203	
4	Interest Synchronization - Tax Impact	WP-3 Interest Sync, Line 4 & 5	(285,182)	(91,483)	
5	Taxes - Total	Line 3 + Line 4	504,133	161,720	665,853
6	Deferred Taxes	WP-11.1 Taxes Detail Column (f)	1,948,086	-	1,948,086
7	Current Taxes	Line 5 - Line 6	(1,443,953)	161,720	(1,282,233)
8	Taxes - Total	Line 6 + Line 7	504,133	161,720	665,853
9	Excess ADIT Amortization	ADJ-20	(212,800)	-	(212,800)
10	Adjusted Taxes - Total	Line 8 + Line 9	$ 291,333	$ 161,720	$ 453,053

Line No.	Description	Reference	Amount
	(a)	(b)	(c)
1	Rate Base	**WP-3.1 Rate Base**	$ 63,773,350
2	Weighted Cost of Debt	**WP-3 Rate of Return**	2.27%
3	Synchronized Interest Expense	**Line 1 x Line 2**	1,449,493
4	Change in State Income Tax Expense	**Line 3 x WP-3 GRCF Column (c), Line 1**	(91,483)
5	Change in Federal Income Tax Expense	**Line 3 x WP-3 GRCF Column (c), Line 3**	$ (285,182)

Line No.	Description	Reference	Percentage	Cost Rate	Rate of Return
	(a)	(b)	(c)	(d)	(e) = (c) * (d)
1	Long Term Debt	**WP-7 Capital Structure**	48.35%	4.70%	2.27%
2	Common Equity	**WP-7 Capital Structure**	51.65%	10.20%	5.27%
3	Total		100.00%		7.54%

Line No.	Description	Rate	Factor
	(a)	(b)	(c)
1	State Income Tax	7.00%	6.31%
2	Federal Taxable Income		93.69%
3	Federal Income Tax	21.00%	19.67%
4	Operating Income		74.01%
5	Gross Revenue Conversion Factor		1.3511

Test Year Ending June 30, 2018 - Based on 2017 Data

Line No.	Description	Reference	Kansas Ending Balance at December 31, 2017	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	Rate Base	WP-3 TDC Rate Base	$ 11,365,133	$ -	$ 11,365,133
2	Revenues	WP-3 TDC Operate Income	50,184	-	50,184
3	Expenses	WP-3 TDC Operate Income	2,247,015	-	2,247,015
4	Net Operating (Loss) Before Taxes	Line 2 - Line 3	(2,196,831)	-	(2,196,831)
5	Income tax	WP ADJ 17 TDC Adjustment	358,069	-	358,069
6	Net Operating Income (Loss) After Taxes	Line 4 - Line 5	(2,554,900)	-	(2,554,900)
7	Current Rate of Return	(Line 6 / Line 1)	-22.48%		-22.48%
8	Rate of Return Requested	WP-3 TDC Rate of Return	7.54%		7.54%
9	Required Net Operating Income	(Line 8 x Line 1)	857,221	-	857,221
10	Gross Revenue Requirement	(Line 9 - Line 6)	3,412,121	-	3,412,121
11	Revenue Requirement Collected by SPP under SPP OATT for Regional Upgrades	WP-3 TDC Operate Income	245,755	-	245,755
12	Annual Total TDC Revenue Requirement:	Line 10 - Line 11	$ 3,166,367	$ -	$ 3,166,367

Test Year Ending June 30, 2018

Line No.	Description	Reference	Kansas Ending Balance at December 31, 2017	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	Electric Plant in Service	**WP ADJ 17 TDC Adjustment**	$ 17,919,609		$ 17,919,609
2	Less: Accumulated Depreciation	**WP ADJ 17 TDC Adjustment**	(4,877,332)		(4,877,332)
3	Net Plant in Service	**Line 1 + Line 2**	13,042,277	-	13,042,277
4	Accumulated Deferred Income Taxes	**WP ADJ 17 TDC Adjustment**	(1,910,880)		(1,910,880)
5	Prepaid Expenses	**WP ADJ 17 TDC Adjustment**	64,364		64,364
6	Material & Supplies	**WP ADJ 17 TDC Adjustment**	144,979		144,979
7	Allowance for Cash Working Capital	**WP ADJ 17 TDC Adjustment**	24,393		24,393
8	Total Rate Base	**Sum Line 3 through Line 7**	$ 11,365,133	$ -	11,365,133

Test Year Ending June 30, 2018

Line No.	Description	Reference	Kansas Ending Balance at December 31, 2017	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	Revenue Credits	**WP ADJ 17 TDC Adjustment**	$ 50,184	$ -	$ 50,184
2	Electric Utility Operating Expenses:				
3	Transmission	**Transmission Expense Details**	1,250,535	-	1,250,535
4	Other Expenses	**Other Expense**	14,424	-	14,424
5	Administrative & General Expenses	**Other Expense**	212,605	-	212,605
6	Depreciation & Amortization Expense	**Other Expense**	414,102	-	414,102
7	Taxes Other than Income Taxes	**Other Expense**	168,185	-	168,185
8	Adjustments	**Rev Credits & Other**	187,163	-	187,163
9	Total Electric Utility Operating Expense		2,247,015	-	2,247,015
10	Total Rev. Rqmt. Collected by SPP under SPP OATT for Regional Upgrades	**WP ADJ 17 TDC Adjustment**	$ 245,755	$ -	$ 245,755

Test Year Ending June 30, 2018 -Based on 2017 Data

Line No.	Description	Reference	Percentage	Cost Rate	Rate of Return
	(a)	(b)	(c)	(d)	(e) = (c) *(d)
1	Long Term Debt	**WP TFR Calculation**	51.08%	5.19%	2.65%
2	Common Equity	**WP TFR Calculation**	48.92%	10.00%	4.89%
3	Total		100.00%		7.54%

Test Year Ending June 30, 2018 -Based on 2017 Data

Line No.	GL Account	Description	Reference	Total Company Ending Balance at December 31, 2017	Transmission / Distribution Revenue Allocator Factor	Amount Allocated to TFR/TDC	Kansas Retail Allocator	Kansas Retail Adjusted Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) * (e)	(g)	(h) = (f) * (g)
1	454010	Rent from Elec Property-Ark	WP ADJ 17 TFR Calculation	$ 25,870	31.64%	$ 8,185	4.15%	$ 339
2	454020	Rent from Elec Property-Ks	WP ADJ 17 TFR Calculation	33,621	31.64%	10,637	4.15%	441
3	454030	Rent from Elec Property-Mo	WP ADJ 17 TFR Calculation	978,244	31.64%	309,494	4.15%	12,833
4	454040	Rent from Elec Property-Okla	WP ADJ 17 TFR Calculation	21,218	31.64%	6,713	4.15%	278
5	457137	Ot El RvOffSys LTFSTF PTP Trns	WP ADJ 17 TFR Calculation	789,688	100%	789,688	4.15%	32,744
6	457138	Ot El RvOffSys NnFrm PTP Trns	WP ADJ 17 TFR Calculation	77,376	100%	77,376	4.15%	3,208
7	457151	Oth El Rev-Off-Sys Transm	WP ADJ 17 TFR Calculation	5,406	100%	5,406	4.15%	224
8		Other Revenues Associated with Loads Outside of Empire's Zone	WP ADJ 17 TFR Calculation	2,791	100%	2,791	4.15%	116
9		Refunds and Surcharges	WP ADJ 17 TFR Calculation	(3,870,834)	100.00%	(3,870,834)	4.84%	(187,163)
10		Total	WP ADJ 17 TDC Adjustment	$ (1,936,621)		$ (2,660,545)		$ (136,979)

Test Year Ending June 30, 2018 -Based on 2017 Data

Line No.	FERC	GL Account	Description	Reference	Total Company: Ending Balance at 12/31/2017	Excluded From Schedule 11 TFR Formula	Schedule 11 Expenses Recovered Through FERC TFR Formula	Kansas: Kansas Retail Allocator	Kansas Allocation	Reclass	Reclassed 12/31/2017 Balance	Additional Schedule Expenses to Be Recovered	Pro Forma Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g) = (e) + (f)	(h)	(i) = (g) x (h)	(j)	(k) = (i) + (j)	(l)	(m) = (k) + (l)
TRANSMISSION EXPENSES													
1	560	560011	Conv & Seminar-Transm Op	*	$ 94,512	$ -	$ 94,512	4.84% (1)	$ 4,579	$ -	$ 4,579	$ -	$ 4,579
2	560	560025	Safety Expenses-Line Eng		528		528	4.84% (1)	26		26		26
3	560	560046	Computer Software-Engineer		40,611		40,611	4.84% (1)	1,968		1,968		1,968
4	560	560449	Transm Operation Super & Engr		-		-	4.84% (1)	-		-		-
5	560	560490	Computer Programming		-		-	4.84% (1)	-		-		-
6	560	560628	T & D Eng-Oper Supervision		105,701		105,701	4.84% (1)	5,121		5,121		5,121
7	560	560629	Transmission System Planning		193,285		193,285	4.84% (1)	9,364		9,364		9,364
8	561	561012	Load Dispatching Training		247		247	4.84% (1)	12		12		12
9	561	561404	Transm System Operations		606,114	(606,114)	-	4.84% (1)	-		-	29,365	29,365
10	561	561450	Transm Oper-Load Dispatching		1,301	(1,301)	-	4.84% (1)	-		-	63	63
11	561	561501	NERC - Facilities Rating		-		-	4.84% (1)	-		-		-
12	561	561505	Power Line Carrier Expenses		27,322		27,322	4.84% (1)	1,324		1,324		1,324
13	562	562010	Transm Substation Operations		210,035		210,035	4.84% (1)	10,176		10,176		10,176
14	562	562111	Exp of Substation & Switchyard		3,528		3,528	4.84% (1)	171		171		171
15	562	562121	Substation Expenses		3,451		3,451	4.84% (1)	167		167		167
16	562	562134	Mtce Of Substation Switchyard		279,305		279,305	4.84% (1)	13,532		13,532		13,532
17	562	562452	Transmission Station Expenses		-		-	4.84% (1)	-		-		-
18	563	563011	Overhead Trans Line Oper-161Kv		5,436		5,436	4.84% (1)	263		263		263
19	563	563012	Overhead Trans Line Oper-69 Kv		34,650		34,650	4.84% (1)	1,679		1,679		1,679
20	563	563014	Overhead Trans Ln Oper-34.5 Kv		2,632		2,632	4.84% (1)	127		127		127
21	563	563015	Overhead Trans Line Oper-Other		4,657		4,657	4.84% (1)	226		226		226
22	565	565413	Trans Of Electricity By Others		-		-	4.84% (1)	-		-		-
23	565	565414	SPP Fixed Chg - Native Load		14,640,246	(14,640,246)	-	5.13% (2)	-		-	750,396	750,396
24	565	565415	SPP Var Chg - Native Load		314,070	(314,070)	-	4.84% (1)	-		-	15,216	15,216
25	565	565416	Non SPP Fixed Chg -Native Load		3,936,506	(3,936,506)	-	4.84% (1)	-		-	190,714	190,714
26	566	566419	Off Sys Sales Trans Costs		-		-	4.84% (1)	-		-		-
27	566	566450	RTO/ISO Development		152,528		152,528	4.84% (1)	7,390		7,390		7,390
28	566	566458	Misc Transmission Expenses		123		123	4.84% (1)	6		6		6
29	566	566459	NERC Compliance/CIPS (706)		104,539		104,539	4.84% (1)	5,065		5,065		5,065
30	566	566462	NERC Compliance/EOP (693)		87,080		87,080	4.84% (1)	4,219		4,219		4,219
31	567	567007	Rents - Transmission		175		175	4.84% (1)	8		8		8
32	568	568631	T & D Eng-Maint Supervision		132,282		132,282	4.84% (1)	6,409		6,409		6,409
33	569	569037	Trans Substa Structure Maint		8,567		8,567	4.84% (1)	415		415		415
34	569	569203	General Maint-System Ops		7,689		7,689	4.84% (1)	373		373		373
35	570	570040	Trans Substa Equip Maintenance		422,019		422,019	4.84% (1)	20,446		20,446		20,446
36	570	570043	Trans Sub Breaker Routine Mtce		120,260		120,260	4.84% (1)	5,826		5,826		5,826
37	570	570044	TransSub Trnsfrmr Routine Mtce		144,275		144,275	4.84% (1)	6,990		6,990		6,990
38	570	570060	Trans Substation Inspections		69,416		69,416	4.84% (1)	3,363		3,363		3,363
39	570	570177	Substation Maintenance - Plant		39,189		39,189	4.84% (1)	1,899		1,899		1,899
40	570	570472	Transmission-Relays & Misc Eq		368,468		368,468	4.84% (1)	17,851		17,851		17,851
41	570	570475	Generation - Relays & Misc Eq		36,879		36,879	4.84% (1)	1,787		1,787		1,787
42	570	570511	Protection Relaying Channel Eq		6,419		6,419	4.84% (1)	311		311		311
43	570	570517	Scada		359,932		359,932	4.84% (1)	17,438		17,438		17,438
44	571	571001	OH Trans Tree Trimming Superv		170,602		170,602	4.84% (1)	8,265		8,265		8,265
45	571	571041	Oh Trans Line Maint-161Kv		(15,242)		(15,242)	4.84% (1)	(738)		(738)		(738)
46	571	571042	Overhead Trans Line Maint-69Kv		30,298		30,298	4.84% (1)	1,468		1,468		1,468
47	571	571043	Oh Trans Line Maint-345 Kv		90,759		90,759	4.84% (1)	4,397		4,397		4,397
48	571	571044	Oh Trans Line Maint-34.5Kv		465		465	4.84% (1)	23		23		23

Test Year Ending June 30, 2018 -Based on 2017 Data

				Total Company				Kansas						
Line No.	FERC	GL Account	Description	Reference	Ending Balance at 12/31/2017	Excluded From Schedule 11 TFR Formula	Schedule 11 Expenses Recovered Through FERC TFR Formula	Kansas Retail Allocator		Kansas Allocation	Reclass	Reclassed 12/31/2017 Balance	Additional Schedule Expenses to Be Recovered	Pro Forma Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g) = (e) + (f)	(h)		(i) = (g) x (h)	(j)	(k) = (i) + (j)	(l)	(m) = (k) + (l)
49	571	571045	Oh Trans Line Maint-Other		10,569		10,569	4.84%	(1)	512		512		512
50	571	571046	Oh Trans Line Tree Trim-345 Kv		49,911		49,911	4.84%	(1)	2,418		2,418		2,418
51	571	571047	Oh Trans Line Tree Trim-161Kv		28,385		28,385	4.84%	(1)	1,375		1,375		1,375
52	571	571048	Oh Trans Line Tree Trim-69 Kv		110,882		110,882	4.84%	(1)	5,372		5,372		5,372
53	571	571050	Oh Trans Ln Tree Trim-34.5 Kv		5,250		5,250	4.84%	(1)	254		254		254
54	571	571051	Oh Trans Line Tree Trim-Other		-		-	4.84%	(1)	-		-		-
55	571	571062	Trans OH reliab - labor&other		19,306		19,306	4.84%	(1)	935		935		935
56	571	571146	Chemical Tree Trim 345Kv		52,572		52,572	4.84%	(1)	2,547		2,547		2,547
57	571	571147	Chemical Tree Trim 161Kv		812,589		812,589	4.84%	(1)	39,368		39,368		39,368
58	571	571148	Chemical Tree Trim 69Kv	*	326,494		326,494	4.84%	(1)	15,818		15,818		15,818
59	571	571150	Chemical Tree Trim 34.5Kv		-		-	4.84%	(1)	-		-		-
60	571	571246	Side Trimming 345Kv		-		-	4.84%	(1)	-		-		-
61	571	571247	Side Trimming 161Kv		-		-	4.84%	(1)	-		-		-
62	571	571248	Side Trimming 69Kv		28,981		28,981	4.84%	(1)	1,404		1,404		1,404
63	571	571250	Side Trimming 34.5Kv		5,147		5,147	4.84%	(1)	249		249		249
64	571	571346	Transm Tree Trimming 345Kv		-		-	4.84%	(1)	-		-		-
65	571	571347	Transm Tree Trimming 161Kv		2,080		2,080	4.84%	(1)	101		101		101
66	571	571348	Trans Tree Trimming 69Kv		765		765	4.84%	(1)	37		37		37
67	571	571350	Transm Tree Trimming 34.5Kv		520		520	4.84%	(1)	25		25		25
68	571	571447	Hydro-Ax Tree Trim 161Kv		-		-	4.84%	(1)	-		-		-
69	571	571448	Hydro-Ax Tree Trim 69Kv		51,333		51,333	4.84%	(1)	2,487		2,487		2,487
70	571	571450	Hydro-Ax Tree Trim 34.5Kv		250		250	4.84%	(1)	12		12		12
71	571	571546	Tree Grinder-Tree Trim 345kv		-		-	4.84%	(1)	-		-		-
72	571	571547	Tree Grinder-Tree Trim 161kv		13,468		13,468	4.84%	(1)	652		652		652
73	571	571548	Tree Grinder-Tree Trim69kv		73,776		73,776	4.84%	(1)	3,574		3,574		3,574
74	571	571646	Dozer-Tree Trim 345kv		-		-	4.84%	(1)	-		-		-
75	571	571647	Dozer-Tree Trim 161kv		577		577	4.84%	(1)	28		28		28
76	571	571648	Dozer-Tree Trim 69kv		172,430		172,430	4.84%	(1)	8,354		8,354		8,354
77	571	571652	Trans 69Kv Pole Inspctn&Trmnt		35,000		35,000	4.84%	(1)	1,696		1,696		1,696
78	571	571656	Trans 345Kv Pole Insptn&Trmnt		60,183		60,183	4.84%	(1)	2,916		2,916		2,916
79	571	571658	Trans 34.5Kv Pole Insptn&Trmnt		426		426	4.84%	(1)	21		21		21
80	571	571740	TGR Tree Trimming-Transmission		4,747		4,747	4.84%	(1)	230		230		230
81	571	571910	Transm Maint 161KV Reliability		38,081		38,081	4.84%	(1)	1,845		1,845		1,845
82	571	571911	Transm Maint 69KV Reliability		(64,495)		(64,495)	4.84%	(1)	(3,125)		(3,125)		(3,125)
83	571	571912	Transm Maint 345KV Reliability		2,134		2,134	4.84%	(1)	103		103		103
84	571	571913	Trans Maint 34.5KV Reliability		659		659	4.84%	(1)	32		32		32
85	571	571920	Transm 69KV Pole Inspec Reliab		280,715		280,715	4.84%	(1)	13,600		13,600		13,600
86	571	571921	Transm 161KV Pole Inspc Reliab		-		-	4.84%	(1)	-		-		-
87	571	571998	Trans Reliab Reg Adj Amort		61,980		61,980	0.00%	(3)	-		-		-
88	571	571999	Trans Reliability Reg Adj				-	0.00%	(3)	-		-		-
89			**Total Transmission Expenses:**		**$ 25,025,575**	**$ (19,498,237)**	**$ 5,527,338**			**$ 264,783**	**$ -**	**$ 264,783**	**$ 985,753**	**$ 1,250,535**

Footnotes:
(1) Allocation WP-12-month average peak
(2) Allocation SPP Fixed Charge WP-12-month average peak
(3) Allocation Direct Assigned

Tickmark:
* = Traced and Agreed To 12/31/17 Trial Balance

Test Year Ending June 30, 2018 -Based on 2017 Data

Line No.	FERC	Description	Reference	Kansas Ending Balance at 12/31/2017	Kansas Pro Forma Adjustments	Kansas Pro Forma Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)
1	Various	Allocated Administrative & General Expenses	**WP ADJ 17 TDC Adjustment**	$ 212,605	$ -	$ 212,605
2	403	Allocated Depreciation & Amortization Expense	**WP ADJ 17 TDC Adjustment**	414,102	-	414,102
3	408	Taxes Other Than Income Taxes	**WP ADJ 17 TDC Adjustment**	168,185	-	168,185
4	557.4	Pool Operation	**WP ADJ 17 TDC Adjustment**	$ 14,424	$ -	$ 14,424

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company Ending Balance	Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Steam	WP-4 PIS Production Detail	$ 788,531,601	$ 1,801,734	$ 790,333,335	$ 37,313,153	$ 25,854	$ 37,339,007
2	Hydro	WP-4 PIS Production Detail	11,069,201	21,678	11,090,879	523,792	1,026	524,818
3	Other	WP-4 PIS Production Detail	539,070,095	2,445,822	541,515,917	25,636,185	115,736	25,751,921
4	Total Production Plant		1,338,670,897	4,269,233	1,342,940,131	63,473,131	142,616	63,615,746
5	Transmission Plant	WP-4 PIS Transmission Detail	372,685,379	-	372,685,379	17,635,395	(17,635,395)	-
6	Distribution Plant	WP-4 PIS Distribution Detail	974,178,778	38,453	974,217,231	53,570,620	38,453	53,609,073
7	General Plant	WP-4 PIS General Detail	89,482,366	(1,830,650)	87,651,716	4,487,526	(565,312)	3,922,214
8	Intangible	WP-4 Intangible Detail	43,353,801	32,333	43,386,133	2,174,186	1,621	2,175,808
9	Total		$ 2,818,371,221	$ 2,509,369	$ 2,820,880,591	$ 141,340,858	$ (18,018,018)	$ 123,322,840

WP-3 Revenue Requirement

Test Year Ending June 30, 2018

Line No.	Description	Total Company					Kansas Jurisdiction					
		CWIP Adjustment	**Common Property Gas Adjustment**	**Merit Increase Adjustment**	**TDC Adjustment**	**Total Pro Forma Adjustments**	**Iatan and Plum Point Prudency Adjustment**	**CWIP Adjustment**	**Common Property Gas Adjustment**	**Merit Increase Adjustment**	**TDC Adjustment**	**Total Pro Forma Adjustments**
	(a)	(b)	(c)	(d)	(e)	(f) = SUM (b) through (e)	(g)	(h)	(i)	(j)	(k)	(l) =SUM (g) through (k)
1	**Adjustment Number**	**ADJ-5**	**ADJ-2**	**ADJ-16**	**ADJ-17**		**ADJ-1**	**ADJ-5**	**ADJ-2**	**ADJ-16**	**ADJ-17**	
2	Steam	$ 1,801,734	$ -	$ -	$ -	$ 1,801,734	$ (59,404) (1)	$ 85,258	$ -	$ -	$ -	$ 25,854
3	Hydro	21,678				21,678		1,026				1,026
4	Other	2,445,822				2,445,822		115,736				115,736
5	Total Production Plant	4,269,233				4,269,233	(59,404)	202,019				142,616
6	Transmission Plant	-				-		-			(17,635,395)	(17,635,395)
7	Distribution Plant	38,453				38,453		38,453				38,453
8	General Plant	346,821	(2,177,471)			(1,830,650)		17,393	(109,200)	19,951	(493,456)	(565,312)
9	Intangible Plant	32,333				32,333		1,621				1,621
10	Total Plant Adjustments (Sum of Line 5 through Line 9)	$ 4,686,840	$ (2,177,471)	$ -	$ -	$ 2,509,369	$ (59,404)	$ 259,487	$ (109,200)	$ 19,951	$ (18,128,852)	$ (18,018,018)

Footnote:
(1) Iatan and Plum Point Adjustment are Kansas Jurisdiction specific per Order 11-EDPE-856-RTS

The Empire District Electric Company
Kansas
Docket No. 19-EPDE-XXX-RTS
Section 4
WP-4.2 Plant in Service

			Total Company										Kansas Jurisdiction	
			Calendar Years Ended						Test Year		Test Year		Test Year	
			12/31/2015		12/31/2016		12/31/2017		6/30/2017		6/30/2018		6/30/2018	
Line No.	FERC	Plant in Service	Reference	Ending Balance	Reference	Ending Balance	Reference	Ending Balance	Reference	Ending Balance	Reference	Ending Balance	Allocation Percentage	Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1		INTANGIBLE PLANT												
2	301	Organization	^	$ 29,940	#	$ 29,940	@	$ 29,940	!	$ 29,940	WP - Plant	$ 29,940	5.01%	$ 1,501
3	302	Franchises	^	1,079,798	#	1,079,798	@	1,079,798	!	1,079,798	WP - Plant	1,079,798	5.01%	54,152
4	303	Misc Intangible	^	38,652,229	#	39,565,657	@	40,259,656	!	39,710,539	WP - Plant	42,244,062	5.01%	2,118,533
5		TOTAL INTANGIBLE PLANT		39,761,968		40,675,395		41,369,395		40,820,277		43,353,801		2,174,186 (1)
6		STEAM												
7	310	Land and Land Rights	^	2,435,380	#	2,488,084	@	2,435,380	!	2,488,084	WP - Plant	2,435,380	4.73%	115,242
8	311	Structures	^	83,003,984	#	84,815,285	@	82,531,039	!	82,422,338	WP - Plant	82,423,179	4.73%	3,900,248
9	312	Boiler Plant	^	528,258,309	#	529,788,746	@	535,460,403	!	535,549,742	WP - Plant	538,317,398	4.73%	25,473,069
10	314	Turbogenerators	^	114,160,151	#	114,323,827	@	117,802,563	!	115,309,929	WP - Plant	119,362,868	4.73%	5,648,226
11	315	Access. Electric	^	37,500,026	#	37,635,204	@	37,987,628	!	37,278,966	WP - Plant	38,126,345	4.73%	1,804,131
12	316	Misc. Equipment	^	7,482,641	#	7,584,301	@	7,785,673	!	7,946,006	WP - Plant	7,866,431	4.73%	372,238
13		TOTAL STEAM PLANT		772,840,492		776,635,448		784,002,685		780,995,065		788,531,601		37,313,153 (2)
14		HYDRO												
15	330	Land and Land Rights	^	226,488	#	226,488	@	226,488	!	226,488	WP - Plant	226,488	4.73%	10,717
16	331	Structures	^	799,026	#	822,591	@	810,803	!	811,928	WP - Plant	811,148	4.73%	38,383
17	332	Dams	^	3,414,912	#	3,414,912	@	3,417,695	!	3,416,107	WP - Plant	3,418,630	4.73%	161,769
18	333	Turbogenerators	^	3,134,261	#	3,134,261	@	3,161,773	!	3,161,773	WP - Plant	4,482,395	4.73%	212,106
19	334	Access. Electric	^	1,404,531	#	1,425,239	@	1,449,463	!	1,404,787	WP - Plant	1,479,085	4.73%	69,990
20	335	Misc. Equipment	^	494,556	#	523,019	@	597,207	!	545,088	WP - Plant	651,456	4.73%	30,827
21		TOTAL HYDRO PLANT		9,473,773		9,546,509		9,663,429		9,566,170		11,069,201		523,792 (2)
22		OTHER												
23	340	Land and Land Rights	^	1,278,438	#	1,269,371	@	1,267,014	!	1,269,371	WP - Plant	1,267,014	4.73%	59,955
24	341	Structures	^	23,044,085	#	40,407,859	@	41,289,141	!	40,946,569	WP - Plant	41,382,733	4.73%	1,958,222
25	342	Fuel Holders	^	7,756,895	#	7,840,940	@	7,857,147	!	7,840,704	WP - Plant	7,877,430	4.73%	372,758
26	343	Prime Movers	^	231,256,476	#	366,819,877	@	366,185,123	!	368,368,654	WP - Plant	368,231,017	4.73%	17,424,616
27	344	Generators	^	55,970,084	#	65,647,771	@	64,542,448	!	65,534,179	WP - Plant	64,559,502	4.73%	3,054,942
28	345	Access. Electric	^	28,658,409	#	45,002,036	@	45,026,683	!	45,129,153	WP - Plant	45,326,432	4.73%	2,144,837
29	346	Misc. Equipment	^	9,033,995	#	10,383,607	@	10,334,144	!	10,479,747	WP - Plant	10,425,968	4.73%	493,355
30		TOTAL OTHER PLANT		356,998,383		537,371,461		536,501,700		539,568,377		539,070,095		25,508,686 (2)
31		Disallowances (Added Back into Rate Base):									WP - Plant	2,694,420	4.73%	127,499
32		MO/AR Disallowances Per Rate Case Orders									WP - Plant	(2,694,420)	4.73%	
33		TRANSMISSION												
34	350	Land and Land Rights	^	11,925,628	#	12,028,040	@	11,923,369	!	11,928,014	WP - Plant	11,923,369	4.73%	564,211
35	352	Structures	^	2,888,275	#	3,047,261	@	2,883,747	!	3,089,447	WP - Plant	3,252,272	4.73%	153,897
36	352.I	Structures and Improvements (Iatan)	^		#		@	23,013	!	23,013	WP - Plant	23,013	4.73%	1,089
37	353	Station Equip.	^	132,989,538	#	144,423,028	@	161,644,682	!	150,680,410	WP - Plant	163,351,416	4.73%	7,729,755
38	353.I	Station Equipment (Iatan)	^		#		@	602,064	!	521,689	WP - Plant	603,764	4.73%	28,570
39	354	Towers & Fixtures	^	2,136,321	#	1,782,962	@	1,817,799	!	1,817,409	WP - Plant	1,921,183	4.73%	90,910
40	355	Poles & Fixtures	^	86,667,843	#	89,437,886	@	90,738,373	!	89,555,957	WP - Plant	95,285,851	4.73%	4,508,907
41	356	OH Conductor	^	79,429,952	#	87,632,213	@	90,058,894	!	88,632,128	WP - Plant	96,324,512	4.73%	4,558,056
42		TOTAL TRANSMISSION PLANT		316,037,557		338,351,390		359,691,942		346,248,069		372,685,379		17,635,395 (2)
43		DISTRIBUTION												
44	360	Land and Land Rights	^	3,995,089	#	4,265,548	@	4,128,843	!	4,128,843	WP - Plant	4,626,086	100%	219,428
45	361	Structures	^	27,397,169	#	26,764,178	@	26,143,005	!	26,407,748	WP - Plant	26,551,179	100%	693,149
46	362	Station Equip.	^	105,145,313	#	109,746,559	@	124,780,102	!	120,209,495	WP - Plant	133,321,697	100%	4,696,247
47	364	Poles & Fixtures	^	187,899,093	#	197,108,766	@	208,028,482	!	202,577,852	WP - Plant	212,240,386	100%	18,779,538
48	365	OH Conductor	^	196,731,664	#	204,080,319	@	210,763,681	!	208,040,103	WP - Plant	213,434,101	100%	13,624,784
49	366	UG Conduit	^	38,986,890	#	40,557,307	@	43,013,010	!	41,401,315	WP - Plant	45,244,141	100%	659,590

			Total Company										**Kansas Jurisdiction**	
			Calendar Years Ended						**Test Year**		**Test Year**		**Test Year**	
			12/31/2015		**12/31/2016**		**12/31/2017**		**6/30/2017**		**6/30/2018**		**6/30/2018**	
Line No.	**FERC**	**Plant in Service**	**Reference**	**Ending Balance**	**Reference**	**Ending Balance**	**Reference**	**Ending Balance**	**Reference**	**Ending Balance**	**Reference**	**Ending Balance**	**Allocation Percentage**	**Ending Balance**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
50	367	UG Conductor	^	60,713,371	#	63,755,405	@	65,807,157	!	64,311,761	WP - Plant	66,852,734	100%	802,117
51	368	Transformers	^	110,407,244	#	114,709,243	@	120,421,884	!	118,274,052	WP - Plant	123,242,975	100%	5,576,568
52	369	Services	^	78,645,963	#	81,029,532	@	84,450,222	!	82,310,827	WP - Plant	86,058,629	100%	4,572,969
53	370	Meters	^	23,335,929	#	24,632,289	@	24,570,957	!	24,996,620	WP - Plant	24,593,635	100%	1,401,538
54	371	Private Lights	^	16,968,401	#	16,996,918	@	17,104,341	!	17,149,964	WP - Plant	17,772,916	100%	1,553,946
55	373	Street Lights	^	19,151,358	#	19,387,155	@	19,717,509	!	19,650,995	WP - Plant	20,088,987	100%	990,744
56	375	Charging Stations	^	-	#	11,439	@	151,313	!	11,439	WP - Plant	151,313	100%	-
57		TOTAL DISTRIBUTION PLANT		869,377,485		903,044,659		949,080,504		929,471,014		974,178,778		53,570,620 (3)
58		GENERAL												
59	389	Land and Land Rights	^	659,081	#	1,160,224	@	1,057,907	!	1,160,224	WP - Plant	1,057,907	5.01%	53,054
60	390	Structure	^	11,005,100	#	11,439,576	@	11,697,714	!	11,435,789	WP - Plant	11,914,537	5.01%	597,512
61	391	Furniture	^	6,229,654	#	6,264,990	@	6,266,370	!	6,284,658	WP - Plant	6,283,777	5.01%	315,130
62	391	Computer Equip.	^	14,044,017	#	14,110,342	@	14,596,362	!	14,993,651	WP - Plant	15,127,945	5.01%	758,664
63	392	Transport. Equip.	^	12,632,828	#	13,682,922	@	14,341,658	!	14,080,418	WP - Plant	14,599,573	5.01%	732,166
64	393	Stores Equip.	^	831,566	#	834,611	@	855,334	!	834,611	WP - Plant	865,162	5.01%	43,388
65	394	Tools	^	6,396,061	#	6,809,051	@	6,974,821	!	6,763,252	WP - Plant	7,097,214	5.01%	355,924
66	395	Lab Equipment	^	1,343,198	#	1,601,176	@	1,985,646	!	1,628,573	WP - Plant	1,994,597	5.01%	100,029
67	396	Power Op. Equip.	^	17,981,052	#	18,680,698	@	18,252,136	!	18,306,794	WP - Plant	18,354,751	5.01%	920,488
68	397	Communication	^	12,118,205	#	11,783,559	@	11,876,741	!	11,816,450	WP - Plant	11,909,664	5.01%	597,268
69	398	Misc. Equipment	^	276,456	#	283,621	@	277,439	!	283,621	WP - Plant	277,238	5.01%	13,903
70		TOTAL GENERAL PLANT		83,517,218		86,650,770		88,182,128		87,588,039		89,482,366		4,487,526 (1)
71		TOTAL PLANT IN SERVICE		$ 2,448,006,875		$ 2,692,275,633		$ 2,768,491,782		$ 2,734,257,011		$ 2,818,371,221		$ 141,340,858
												WP-2 Sec 4 Plant		WP-2 Sec 4 Plant

Footnotes:
(1) Allocation to Kansas General Plant Intangible (WP PIS Intangible Detail)
(2) Allocation to Kansas using 12-month Average Peak (WP PIS Production Detail)
(3) Direct Assigned less Kansas Wholesale

Tickmarks:
^ = Traced and Agreed to 12-15 Plt in Srv
# = Traced and Agreed to 12-16 Plt in Srv
@ = 12-17 Plt in Serv
! = Traced and Agreed to 06-17 Plt in Srv

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company Ending Balance	Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Steam	WP-5 AD Production	$ 206,419,517	$ -	$ 206,419,517	$ 7,943,883	$ (3,242)	$ 7,940,641
2	Hydro	WP-5 AD Production	3,214,571	-	3,214,571	152,113	32	152,145
3	Other	WP-5 AD Production	133,707,752	-	133,707,752	6,327,023	3,094	6,330,117
4	Total Production Plant		343,341,840	-	343,341,840	14,423,019	(116)	14,422,903
5	Transmission Plant	WP-5 AD Transmission	104,205,042	-	104,205,042	4,930,961	(4,930,961)	-
6	Distribution Plant	WP-5 AD Distribution	441,007,102	-	441,007,102	24,267,353	1,455	24,268,808
7	General Plant	WP-5 AD General	51,464,931	-	51,464,931	2,580,958	(330,164)	2,250,794
8	Amortization Of Electric Plant	WP-5 AD Intangible	20,837,351	-	20,837,351	1,044,990	162	1,045,152
9	Total		$ 960,856,266	$ -	$ 960,856,266	$ 47,247,281	$ (5,259,623)	$ 41,987,657

Test Year Ending June 30, 2018

		Kansas Jurisdiction					
Line No.	**Description**	**Iatan and Plum Point Prudency Adjustment**	**CWIP Adjustment**	**Common Property Gas Adjustment**	**Merit Increase Adjustment**	**TDC Adjustment**	**Total Pro Forma Adjustments**
	(a)	(b)	(c)	(d)	(e)	(f)	(g) = SUM (b) through (f)
1	**Adjustment Number**	**ADJ-1**	**ADJ-5**	**ADJ-2**	**ADJ-16**	**ADJ-17**	
2	Steam	$ (7,488) (1)	$ 4,246	$ -	$ -	$ -	$ (3,242)
3	Hydro		32				32
4	Other		3,094				3,094
5	Total Production Plant AD	(7,488)	7,372	-	-	-	(116)
6	Transmission Plant AD					(4,930,961)	(4,930,961)
7	Distribution Plant AD		1,455				1,455
8	General Plant AD		883	(68,435)	632	(263,244)	(330,164)
9	Intangible Plant AD		162				162
10	Total AD Adjustments (Sum of Line 5 through Line 9)	$ (7,488)	$ 9,872	$ (68,435)	$ 632	$ (5,194,205)	$ (5,259,623)

Footnote:
(1) Iatan and Plum Point Adjustment are Kansas Jurisdiction specific per Order 11-EDPE-856-RTS

Line No.	FERC	Depreciation Reserve Description	Reference	Total Company									
				Calendar Years Ended						Test Year		Test Year	
				12/31/2015		12/31/2016		12/31/2017		6/30/2017		6/30/2018	
				Accumulated Depreciation	Amortization	Accumulated Depreciation	Amortization	Accumulated Depreciation	Amortization	Accumulated Depreciation	Amortization	Accumulated Depreciation	Amortization
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1		INTANGIBLE PLANT											
2	301	Organization	WP-5 Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	302	Franchises	WP-5 Plant in Service	-	855,461	-	890,883	-	926,304	-	908,594	-	944,015
4	303	Misc Intangible	WP-5 Plant in Service	-	14,715,554	-	16,017,415	-	18,003,327	-	16,244,300	-	19,893,336
5		TOTAL INTANGIBLE PLANT		-	15,571,015	-	16,908,298	-	18,929,632	-	17,152,894	-	20,837,351
6		STEAM											
7	311R	Structures	WP-5 Plant in Service	12,819,071	3,544,751	17,177,729	3,544,751	16,495,939	3,544,751	15,621,105	3,544,751	17,367,918	3,544,751
8	312R	Boiler Plant	WP-5 Plant in Service	80,710,556	23,321,791	101,166,527	23,321,791	110,984,290	23,321,791	106,514,460	23,321,791	118,694,697	23,321,791
9	314R	Turbogenerators	WP-5 Plant in Service	13,739,195	8,319,550	16,660,253	8,319,550	18,772,800	8,319,550	17,879,634	8,319,550	20,267,774	8,319,550
10	315R	Access. Electric	WP-5 Plant in Service	7,756,283.44	2,101,101.94	9,007,452.00	2,101,101.94	9,430,306	2,101,102	9,003,807	2,101,102	9,841,730	2,101,102
11	316R	Misc. Equipment	WP-5 Plant in Service	2,555,169	25,758	2,770,764	25,758	2,858,853	25,758	2,841,488	25,758	2,934,445	25,758
12		TOTAL STEAM PLANT		117,580,275	37,312,953	146,782,725	37,312,953	158,542,188	37,312,953	151,860,495	37,312,953	169,106,564	37,312,953
13		HYDRO											
14	331	Structures	WP-5 Plant in Service	335,622	-	350,975	-	310,330	-	325,732	-	317,353	-
15	332	Dams	WP-5 Plant in Service	1,404,787	-	1,448,636	-	1,503,965	-	1,477,352	-	1,522,763	-
16	333	Turbogenerators	WP-5 Plant in Service	547,988	-	628,626	-	700,692	-	664,621	-	739,577	-
17	334	Access. Electric	WP-5 Plant in Service	335,851	-	364,207	-	394,155	-	379,392	-	410,491	-
18	335	Misc. Equipment	WP-5 Plant in Service	223,840	-	238,032	-	219,231	-	218,711	-	224,387	-
19		TOTAL HYDRO PLANT		2,848,089	-	3,030,476	-	3,128,374	-	3,065,808	-	3,214,571	-
20		OTHER											
21	341	Structures	WP-5 Plant in Service	8,487,632	-	8,377,285	-	9,563,162	-	9,058,963	-	10,107,573	-
22	342	Fuel Holders	WP-5 Plant in Service	6,137,510	-	4,832,071	-	5,034,690	-	4,933,331	-	5,136,292	-
23	343	Prime Movers	WP-5 Plant in Service	72,244,921	-	76,493,073	-	81,929,176	-	80,504,574	-	85,850,988	-
24	344	Generators	WP-5 Plant in Service	19,389,606	-	17,972,557	-	17,274,083	-	18,572,569	-	17,968,288	-
25	345	Access. Electric	WP-5 Plant in Service	8,348,158	-	9,258,588	-	10,212,298	-	9,844,959	-	10,521,582	-
26	346	Misc. Equipment	WP-5 Plant in Service	5,044,700	-	3,941,383	-	5,409,639	-	4,047,770	-	4,123,029	-
27		TOTAL OTHER PLANT		119,652,528	-	120,874,958	-	129,423,047	-	126,962,166	-	133,707,752	-
28		TRANSMISSION											
29	352	Structures	WP-5 Plant in Service	1,358,134	-	1,416,481	-	1,442,016	-	1,429,083	-	1,443,193	-
30	352	Structures (Iatan)	WP-5 Plant in Service	23,161	-	44,417	-	44,872	-	44,645	-	45,100	-
31	353	Station Equip.	WP-5 Plant in Service	43,120,021	-	44,828,296	-	45,496,015	-	45,443,010	-	45,652,842	-
32	353	Station Eq. (Iatan)	WP-5 Plant in Service	502,363	-	522,876	-	528,089	-	519,623	-	533,731	-
33	354	Towers & Fixtures	WP-5 Plant in Service	904,956	-	936,501	-	966,597	-	951,457	-	979,199	-
34	355	Poles & Fixtures	WP-5 Plant in Service	23,926,996	-	24,552,275	-	26,931,176	-	25,779,383	-	28,335,419	-
35	356	OH Conductor	WP-5 Plant in Service	25,212,436	-	25,211,539	-	26,414,186	-	25,705,808	-	27,215,556	-
36		TOTAL TRANSMISSION PLANT		95,048,068	-	97,512,385	-	101,822,951	-	99,873,008	-	104,205,042	-
37		DISTRIBUTION											
38	361	Structures	WP-5 Plant in Service	5,430,683	-	4,849,735	-	5,214,694	-	4,989,837	-	5,389,058	-
39	362	Station Equip.	WP-5 Plant in Service	36,717,734	-	37,835,288	-	39,354,264	-	38,409,651	-	40,093,785	-
40	364	Poles & Fixtures	WP-5 Plant in Service	93,218,897	-	97,481,336	-	101,499,908	-	100,285,140	-	104,547,454	-
41	365	OH Conductor	WP-5 Plant in Service	85,435,566	-	91,233,565	-	97,390,446	-	94,363,801	-	100,964,312	-
42	366	UG Conduit	WP-5 Plant in Service	16,867,109	-	18,215,092	-	19,087,415	-	18,498,598	-	19,799,229	-
43	367	UG Conductor	WP-5 Plant in Service	31,659,351	-	33,546,106	-	35,379,698	-	34,430,623	-	36,512,680	-
44	368	Transformers	WP-5 Plant in Service	40,230,795	-	42,244,763	-	43,886,741	-	43,540,972	-	45,208,329	-
45	369	Services	WP-5 Plant in Service	53,038,844	-	56,627,155	-	59,988,024	-	58,333,160	-	61,886,629	-
46	370	Meters	WP-5 Plant in Service	8,119,940	-	8,654,544	-	7,438,035	-	8,718,544	-	7,661,365	-
47	371	Private Lights	WP-5 Plant in Service	12,286,788	-	12,715,309	-	13,112,090	-	13,045,768	-	13,571,938	-
48	373	Street Lights	WP-5 Plant in Service	4,919,032	-	5,145,033	-	5,041,833	-	5,291,094	-	5,365,363	-
49	375	Charging Stations	WP-5 Plant in Service	-	-	505	-	3,177	-	791	-	6,960	-
50		TOTAL DISTRIBUTION PLANT		387,924,739	-	408,548,430	-	427,396,326	-	419,907,978	-	441,007,102	-
51		GENERAL											
52	390	Structure	WP-5 Plant in Service	6,415,295	-	6,694,077	-	6,940,901	-	6,792,553	-	7,096,789	-
53	391	Furniture	WP-5 Plant in Service	2,097,995	-	2,375,132	-	2,644,677	-	2,507,848	-	2,777,985	-
54	391	Computer Equip.	WP-5 Plant in Service	10,233,721	-	11,079,039	-	11,367,236	-	11,737,764	-	12,030,647	-

				Total Company									
				Calendar Years Ended						Test Year		Test Year	
				12/31/2015		12/31/2016		12/31/2017		6/30/2017		6/30/2018	
Line No.	**FERC**	**Depreciation Reserve Description**	**Reference**	**Accumulated Depreciation**	**Amortization**	**Accumulated Depreciation**	**Amortization**	**Accumulated Depreciation**	**Amortization**	**Accumulated Depreciation**	**Amortization**	**Accumulated Depreciation**	**Amortization**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
55	392	Transport. Equip.	WP-5 Plant in Service	6,942,063	-	7,001,497	-	7,935,351	-	7,474,486	-	8,360,115	-
56	393	Stores Equip.	WP-5 Plant in Service	387,978	-	384,453	-	406,253	-	394,298	-	418,439	-
57	394	Tools	WP-5 Plant in Service	3,527,614	-	3,800,385	-	3,975,735	-	3,900,407	-	4,146,997	-
58	395	Lab Equipment	WP-5 Plant in Service	861,756	-	897,553	-	938,641	-	916,640	-	962,133	-
59	396	Power Op. Equip.	WP-5 Plant in Service	7,672,706	-	7,125,175	-	7,970,305	-	7,620,526	-	8,460,466	-
60	397	Communication	WP-5 Plant in Service	6,354,716	-	6,247,668	-	6,747,358	-	6,507,329	-	7,009,743	-
61	398	Misc. Equipment	WP-5 Plant in Service	181,030	-	192,150	-	196,455	-	197,395	-	201,617	-
62		TOTAL GENERAL PLANT		44,674,873	-	45,797,128	-	49,122,913	-	48,049,245	-	51,464,931	-
63		TOTAL DEPRECIATION RESERVE		$ 767,728,571	$ 52,883,968	$ 822,546,102	$ 54,221,251	$ 869,435,800	$ 56,242,585	$ 849,718,700	$ 54,465,847	$ 902,705,962	$ 58,150,304

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/15	Accumulated Depreciation	Amortization	Net Plant Balance	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/16	Accumulated Depreciation	Amortization	Net Plant Balance
1	AMORTIZATION	12-15 Plt in Svc Depr	301	Organization	$ 29,940	$ -	$ -	$ 29,940	12-16 Plt in Svc Depr	301	Organization	$ 29,940	$ -	$ -	$ 29,940
2	AMORTIZATION		302	Franchises	1,079,798	-	855,461	224,337		302	Franchises	1,079,798	-	890,883	188,916
3	AMORTIZATION		303	Misc Intangible	38,652,229	-	14,715,554	23,936,675		303	Misc Intangible	39,565,657	-	16,017,415	23,548,242
4			**INTANGIBLE**		**39,761,968**	**-**	**15,571,015**	**24,190,953**		**INTANGIBLE**		**40,675,395**	**-**	**16,908,298**	**23,767,097**
5			310R	Land	125,248	-		125,248		310R	Land	125,248	-		125,248
6	STEAM		311R	Structures	2,748,112	961,286		1,786,827		311R	Structures	2,896,112	3,987,908		(1,091,795)
7	STEAM		312R	Boiler Plant	127,842	(4,502,447)		4,630,289		312R	Boiler Plant	65,560	(516,093)		581,652
8	STEAM		314R	Turbogenerators	-	(1,390,628)		1,390,628		314R	Turbogenerators	-	(87,198)		87,198
9	STEAM		315R	Access. Electric	409,165	266,769		142,397		315R	Access. Electric	409,165	706,244		(297,078)
10	STEAM		316R	Misc. Equipment	-	41,047		(41,047)		316R	Misc. Equipment	-	6,709		(6,709)
11			**RIVERTON**		**3,410,368**	**(4,623,973)**	**-**	**8,034,342**		**RIVERTON**		**3,496,085**	**4,097,569**	**-**	**(601,484)**
12			310A	Land	1,224,747	-		1,224,747		310A	Land	1,277,451	-		1,277,451
13	STEAM		311A	Structures	20,663,010	4,934,264		15,728,745		311A	Structures	21,042,416	5,552,220		15,490,196
14	STEAM		312A	Boiler Plant	217,171,888	30,491,867		186,680,021		312A	Boiler Plant	218,630,527	40,700,372		177,930,155
15	STEAM		312AT	(Unit Train)	-	-		-		312AT	(Unit Train)	-	-		-
16	STEAM		314A	Turbogenerators	35,930,702	4,532,758		31,397,943		314A	Turbogenerators	36,146,628	4,732,337		31,414,291
17	STEAM		315A	Access. Electric	6,852,562	2,380,239		4,472,324		315A	Access. Electric	6,910,007	2,602,090		4,307,918
18	STEAM		316A	Misc. Equipment	2,199,712	1,024,687		1,175,025		316A	Misc. Equipment	2,340,825	1,103,409		1,237,416
19			**ASBURY**		**284,042,621**	**43,363,815**	**-**	**240,678,806**		**ASBURY**		**286,347,855**	**54,690,428**	**-**	**231,657,426**
20			310I	Land	121,639	-		121,639		310I	Land	121,639	-		121,639
21	STEAM		311I	Structures	4,136,515	2,578,129		1,558,387		311I	Structures	4,098,282	2,608,785		1,489,497
22	STEAM		312I	Boiler Plant	74,130,151	30,435,753		43,694,398		312I	Boiler Plant	73,985,858	32,056,778		41,929,080
23	STEAM		312IT	(Unit Train)	329,005	97,911		231,094		312IT	(Unit Train)	329,005	118,863		210,141
24	STEAM		314I	Turbogenerators	12,076,988	4,844,540		7,232,448		314I	Turbogenerators	12,125,640	5,082,609		7,043,030
25	STEAM		315I	Access. Electric	7,931,840	3,207,924		4,723,916		315I	Access. Electric	7,953,510	3,358,833		4,594,677
26	STEAM		316I	Misc. Equipment	1,434,355	1,019,945		414,411		316I	Misc. Equipment	1,390,590	675,824		714,766
27			**IATAN 1**		**100,160,493**	**42,184,202**	**-**	**57,976,292**		**IATAN 1**		**100,004,523**	**43,901,693**	**-**	**56,102,831**
28	STEAM		311I2	Structures	20,379,082	1,848,594		18,530,488		311I2	Structures	20,367,575	2,203,554		18,164,022
29	STEAM		311.1	Reg Plan Amort			3,544,751	(3,544,751)		311.1	Reg Plan Amort			3,544,751	(3,544,751)
30	STEAM		312I2	Boiler Plant	138,234,757	12,796,565		125,438,192		312I2	Boiler Plant	138,388,514	15,159,157		123,229,357
31	STEAM		312.1	Reg Plan Amort			23,321,791	(23,321,791)		312.1	Reg Plan Amort			23,321,791	(23,321,791)
32	STEAM		314I2	Turbogenerators	47,884,728	4,189,432		43,695,296		314I2	Turbogenerators	47,790,087	4,993,334		42,796,754
33	STEAM		314.1	Reg Plan Amort			8,319,550	(8,319,550)		314.1	Reg Plan Amort			8,319,550	(8,319,550)
34	STEAM		315I2	Access. Electric	12,286,985	1,061,296		11,225,689		315I2	Access. Electric	12,292,217	1,294,693		10,997,524
35	STEAM		315.1	Reg Plan Amort			2,101,102	(2,101,102)		315.1	Reg Plan Amort			2,101,102	(2,101,102)
36	STEAM		316I2	Misc. Equipment	237,494	19,222		218,272		316I2	Misc. Equipment	271,881	464,290		(192,409)
37	STEAM		316.1	Reg Plan Amort			25,758	(25,758)		316.1	Reg Plan Amort			25,758	(25,758)
38			**IATAN 2**		**219,023,046**	**19,915,109**	**37,312,953**	**161,794,984**		**IATAN 2**		**219,110,275**	**24,115,027**	**37,312,953**	**157,682,295**
39			310IC		7,217	-		7,217		310IC		7,217	-		7,217
40	STEAM		311IC	Structures	14,411,331	674,833		13,736,498		311IC	Structures	15,745,063	579,899		15,165,164
41	STEAM		312IC	Boiler Plant	39,236,176	4,446,735		34,789,441		312IC	Boiler Plant	39,352,431	5,236,581		34,115,850
42	STEAM		314IC	Turbogenerators	1,272,286	60,172		1,212,114		314IC	Turbogenerators	1,265,165	85,218		1,179,947
43	STEAM		315IC	Access. Electric	4,765,381	236,944		4,528,436		315IC	Access. Electric	4,771,307	333,351		4,437,956
44	STEAM		316IC	Misc. Equipment	642,526	39,875		602,651		316IC	Misc. Equipment	612,550	48,364		564,185
45			**IATAN COMMON**		**60,334,917**	**5,458,559**	**-**	**54,876,357**		**IATAN COMMON**		**61,753,733**	**6,283,413**	**-**	**55,470,320**
46			310P	Structures	956,529	-		956,529		310P		956,529	-		956,529
47	STEAM		311P	Boiler Plant	20,665,934	1,821,966		18,843,969		311P	Structures	20,665,836	2,245,364		18,420,472
48	STEAM		312P	Turbogenerators	53,748,952	5,086,102		48,662,851		312P	Boiler Plant	53,757,315	6,216,577		47,540,738
49	STEAM		312PT	(Unit Train)	5,279,537	1,858,069		3,421,468		312PT	(Unit Train)	5,279,537	2,194,292		3,085,245
50	STEAM		314P	Turbogenerators	16,995,447	1,502,921		15,492,526		314P	Turbogenerators	16,996,307	1,853,953		15,142,355
51	STEAM		315P	Access. Electric	5,254,093	603,112		4,650,981		315P	Access. Electric	5,298,997	712,242		4,586,755
52	STEAM		316P	Misc. Equipment	2,968,554	410,393		2,558,161		316P	Misc. Equipment	2,968,456	472,167		2,496,288
53			**PLUM POINT**		**105,869,046**	**11,282,562**	**-**	**94,586,484**		**PLUM POINT**		**105,922,977**	**13,694,595**	**-**	**92,228,382**
54			330	Land	226,488	-		226,488		330	Land	226,488	-		226,488
55	HYDRO		331	Structures	799,026	335,622		463,405		331	Structures	822,591	350,975		471,616
56	HYDRO		332	Dams	3,414,912	1,404,787		2,010,125		332	Dams	3,414,912	1,448,636		1,966,277
57	HYDRO		333	Turbogenerators	3,134,261	547,988		2,586,272		333	Turbogenerators	3,134,261	628,626		2,505,635
58	HYDRO		334	Access. Electric	1,404,531	335,851		1,068,679		334	Access. Electric	1,425,239	364,207		1,061,032
59	HYDRO		335	Misc. Equipment	494,556	223,840		270,715		335	Misc. Equipment	523,019	238,032		284,986
60			**HYDRO**		**9,473,773**	**2,848,089**	**-**	**6,625,685**		**HYDRO**		**9,546,509**	**3,030,476**	**-**	**6,516,033**
61			340E	Land	163,097	-		163,097		340E	Land	165,454	-		165,454
62	OTHER		341E	Structures	2,134,907	1,989,785		145,121		341E	Structures	2,179,189	1,464,837		714,351
63	OTHER		342E	Fuel Holders	1,290,095	1,565,630		(275,535)		342E	Fuel Holders	1,290,095	1,323,529		(33,434)
64	OTHER		343E	Prime Movers	27,630,902	16,764,731		10,866,171		343E	Prime Movers	26,530,279	16,576,659		9,953,620
65	OTHER		344E	Generators	4,737,700	6,737,484		(1,999,784)		344E	Generators	4,731,013	4,148,786		582,228
66	OTHER		345E	Access. Electric	2,263,612	1,147,402		1,116,210		345E	Access. Electric	2,063,509	1,256,066		807,443
67	OTHER		346E	Misc. Equipment	1,768,036	3,163,476		(1,395,440)		346E	Misc. Equipment	1,807,249	1,926,406		(119,157)

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/17	Accumulated Depreciation	Amortization	Net Plant Balance	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/17	Accumulated Depreciation	Amortization	Net Plant Balance
1	AMORTIZATION	12-17 Plt in Svc Depr	301	Organization	$ 29,940	$ -	$ -	$ 29,940	06-17 Plt in Svc Depr	301	Organization	$ 29,940	$ -	$ -	$ 29,940
2	AMORTIZATION		302	Franchises	1,079,798	-	926,304	153,494		302	Franchises	1,079,798	-	908,594	171,205
3	AMORTIZATION		303	Misc Intangible	40,259,656	-	18,003,327	22,256,329		303	Misc Intangible	39,710,539	-	16,244,300	23,466,239
4			**INTANGIBLE**		**41,369,395**	**-**	**18,929,632**	**22,439,763**		**INTANGIBLE**		**40,820,277**	**-**	**17,152,894**	**23,667,384**
5			310R	Land	-	-		-		310R	Land	-	-		-
6	STEAM		311R	Structures	171,409	1,502,289		(1,330,880)		311R	Structures	265,268	1,492,650		(1,227,382)
7	STEAM		312R	Boiler Plant	64,210	(511,741)		575,951		312R	Boiler Plant	64,210	(514,564)		578,774
8	STEAM		314R	Turbogenerators	-	(87,198)		87,198		314R	Turbogenerators	-	(87,198)		87,198
9	STEAM		315R	Access. Electric	10,916	326,223		(315,307)		315R	Access. Electric	10,916	325,749		(314,832)
10	STEAM		316R	Misc. Equipment	-	6,709		(6,709)		316R	Misc. Equipment	-	6,709		(6,709)
11			**RIVERTON**		**246,535**	**1,236,282**	**-**	**(989,746)**		**RIVERTON**		**340,395**	**1,223,345**	**-**	**(882,950)**
12			310A	Land	1,349,995	-		1,349,995		310A	Land	1,402,699	-		1,402,699
13	STEAM		311A	Structures	21,067,622	6,230,349		14,837,273		311A	Structures	21,162,882	5,930,293		15,232,589
14	STEAM		312A	Boiler Plant	219,322,560	47,166,955		172,155,605		312A	Boiler Plant	221,397,313	45,289,744		176,107,569
15	STEAM		312AT	(Unit Train)	-	-		-		312AT	(Unit Train)	-	-		-
16	STEAM		314A	Turbogenerators	36,558,010	5,446,974		31,111,036		314A	Turbogenerators	36,528,087	5,232,152		31,295,935
17	STEAM		315A	Access. Electric	6,886,420	2,835,536		4,050,884		315A	Access. Electric	6,913,897	2,716,721		4,197,176
18	STEAM		316A	Misc. Equipment	2,444,012	1,137,672		1,306,340		316A	Misc. Equipment	2,555,146	1,124,412		1,430,734
19			**ASBURY**		**287,628,619**	**62,817,486**	**-**	**224,811,133**		**ASBURY**		**289,960,024**	**60,293,322**	**-**	**229,666,702**
20			310I	Land	121,639	-		121,639		310I	Land	121,639	-		121,639
21	STEAM		311I	Structures	4,099,257	2,680,267		1,418,990		311I	Structures	4,099,257	2,643,038		1,456,219
22	STEAM		312I	Boiler Plant	75,183,113	33,055,673		42,127,440		312I	Boiler Plant	73,822,711	32,355,055		41,467,656
23	STEAM		312IT	(Unit Train)	329,005	139,818		189,186		312IT	(Unit Train)	329,005	129,337		199,668
24	STEAM		314I	Turbogenerators	14,434,642	5,392,445		9,042,197		314I	Turbogenerators	12,068,329	5,237,753		6,830,576
25	STEAM		315I	Access. Electric	8,485,139	3,562,941		4,922,199		315I	Access. Electric	7,961,261	3,456,964		4,504,296
26	STEAM		316I	Misc. Equipment	1,383,838	682,327		701,512		316I	Misc. Equipment	1,410,851	686,867		723,984
27			**IATAN 1**		**104,036,632**	**45,513,471**	**-**	**58,523,162**		**IATAN 1**		**99,813,051**	**44,509,014**	**-**	**55,304,037**
28	STEAM		311I2	Structures	20,677,618	2,508,771		18,168,847		311I2	Structures	20,404,556	2,355,753		18,048,804
29	STEAM		311.1	Reg Plan Amort			3,544,751	(3,544,751)		311.05	Reg Plan Amort			3,544,751	(3,544,751)
30	STEAM		312I2	Boiler Plant	142,672,790	16,828,918		125,843,872		312I2	Boiler Plant	142,303,121	15,960,076		126,343,045
31	STEAM		312.1	Reg Plan Amort			23,321,791	(23,321,791)		312.05	Reg Plan Amort			23,321,791	(23,321,791)
32	STEAM		314I2	Turbogenerators	48,298,651	5,688,145		42,610,506		314I2	Turbogenerators	48,296,200	5,361,500		42,934,701
33	STEAM		314.1	Reg Plan Amort			8,319,550	(8,319,550)		314.05	Reg Plan Amort			8,319,550	(8,319,550)
34	STEAM		315I2	Access. Electric	12,400,146	1,453,944		10,946,201		315I2	Access. Electric	12,310,254	1,356,406		10,953,847
35	STEAM		315.1	Reg Plan Amort			2,101,102	(2,101,102)		315.05	Reg Plan Amort			2,101,102	(2,101,102)
36	STEAM		316I2	Misc. Equipment	345,670	469,892		(124,222)		316I2	Misc. Equipment	339,750	466,923		(127,174)
37	STEAM		316.1	Reg Plan Amort			25,758	(25,758)		316.05	Reg Plan Amort			25,758	(25,758)
38			**IATAN 2**		**224,394,874**	**26,949,671**	**37,312,953**	**160,132,251**		**IATAN 2**		**223,653,880**	**25,500,658**	**37,312,953**	**160,840,270**
39			310IC		7,217	-		7,217		310IC		7,217	-		7,217
40	STEAM		311IC	Structures	15,835,911	865,432		14,970,479		311IC	Structures	15,812,475	722,433		15,090,042
41	STEAM		312IC	Boiler Plant	38,682,104	4,511,391		34,170,713		312IC	Boiler Plant	38,270,645	4,125,956		34,144,688
42	STEAM		314IC	Turbogenerators	1,369,532	108,909		1,260,623		314IC	Turbogenerators	1,265,165	97,062		1,168,103
43	STEAM		315IC	Access. Electric	4,799,490	425,310		4,374,180		315IC	Access. Electric	4,783,118	379,223		4,403,896
44	STEAM		316IC	Misc. Equipment	643,697	27,472		616,225		316IC	Misc. Equipment	671,804	53,105		618,698
45			**IATAN COMMON**		**61,337,951**	**5,938,515**	**-**	**55,399,437**		**IATAN COMMON**		**60,810,423**	**5,377,779**	**-**	**55,432,644**
46			310P		956,529	-		956,529		310P		956,529	-		956,529
47	STEAM		311P	Structures	20,679,222	2,708,831		17,970,391		311P	Structures	20,677,900	2,476,939		18,200,961
48	STEAM		312P	Boiler Plant	53,997,832	7,334,214		46,663,618		312P	Boiler Plant	54,083,201	6,806,492		47,276,709
49	STEAM		312PT	(Unit Train)	5,208,789	2,459,060		2,749,728		312PT	(Unit Train)	5,279,537	2,362,365		2,917,172
50	STEAM		314P	Turbogenerators	17,141,729	2,223,525		14,918,204		314P	Turbogenerators	17,152,148	2,038,365		15,113,783
51	STEAM		315P	Access. Electric	5,405,516	826,352		4,579,164		315P	Access. Electric	5,299,520	768,745		4,530,775
52	STEAM		316P	Misc. Equipment	2,968,456	534,782		2,433,674		316P	Misc. Equipment	2,968,456	503,471		2,464,985
53			**PLUM POINT**		**106,358,073**	**16,086,764**	**-**	**90,271,308**		**PLUM POINT**		**106,417,292**	**14,956,377**	**-**	**91,460,915**
54			330	Land	226,488	-		226,488		330	Land	226,488	-		226,488
55	HYDRO		331	Structures	810,803	310,330		500,472		331	Structures	811,928	325,732		486,196
56	HYDRO		332	Dams	3,417,695	1,503,965		1,913,730		332	Dams	3,416,107	1,477,352		1,938,755
57	HYDRO		333	Turbogenerators	3,161,773	700,692		2,461,081		333	Turbogenerators	3,161,773	664,621		2,497,152
58	HYDRO		334	Access. Electric	1,449,463	394,155		1,055,308		334	Access. Electric	1,404,787	379,392		1,025,395
59	HYDRO		335	Misc. Equipment	597,207	219,231		377,976		335	Misc. Equipment	545,088	218,711		326,377
60			**HYDRO**		**9,663,429**	**3,128,374**	**-**	**6,535,055**		**HYDRO**		**9,566,170**	**3,065,808**	**-**	**6,500,362**
61			340E	Land	163,097	-		163,097		340E	Land	165,454	-		165,454
62	OTHER		341E	Structures	2,315,541	1,549,277		766,264		341E	Structures	2,276,249	1,506,338		769,911
63	OTHER		342E	Fuel Holders	1,292,806	1,378,881		(86,075)		342E	Fuel Holders	1,290,095	1,351,181		(61,086)
64	OTHER		343E	Prime Movers	26,607,753	17,377,240		9,230,513		343E	Prime Movers	26,529,166	16,996,814		9,532,353
65	OTHER		344E	Generators	5,496,131	4,299,329		1,196,801		344E	Generators	4,731,013	4,224,133		506,880
66	OTHER		345E	Access. Electric	2,066,844	1,362,498		704,346		345E	Access. Electric	2,063,509	1,309,388		754,121
67	OTHER		346E	Misc. Equipment	1,817,133	2,000,300		(183,168)		346E	Misc. Equipment	1,881,875	1,966,168		(84,294)

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/18	Accumulated Depreciation	Amortization	Net Plant Balance
1	AMORTIZATION	06-18 Plt in Svc Depr	301	Organization	$ 29,940	$ -	$ -	$ 29,940
2	AMORTIZATION		302	Franchises	1,079,798	-	944,015	135,783
3	AMORTIZATION		303	Misc Intangible	42,244,062	-	19,893,336	22,350,726
4			**INTANGIBLE**		**43,353,801**	**-**	**20,837,351**	**22,516,449**
5			310R	Land	-	-		-
6	STEAM		311R	Structures	171,409	1,509,883		(1,338,474)
7	STEAM		312R	Boiler Plant	64,210	(508,908)		573,118
8	STEAM		314R	Turbogenerators	-	(87,198)		87,198
9	STEAM		315R	Access. Electric	10,916	326,699		(315,783)
10	STEAM		316R	Misc. Equipment	-	6,709		(6,709)
11			**RIVERTON**		**246,535**	**1,247,186**	**-**	**(1,000,650)**
12			310A	Land	1,349,995	-		1,349,995
13	STEAM		311A	Structures	21,067,718	6,639,033		14,428,685
14	STEAM		312A	Boiler Plant	219,340,546	51,808,176		167,532,371
15	STEAM		312AT	(Unit Train)	-	-		-
16	STEAM		314A	Turbogenerators	36,768,702	6,191,192		30,577,509
17	STEAM		315A	Access. Electric	6,886,420	2,956,600		3,929,820
18	STEAM		316A	Misc. Equipment	2,486,231	1,175,706		1,310,525
19			**ASBURY**		**287,899,612**	**68,770,707**	**-**	**219,128,904**
20			310I	Land	121,639	-		121,639
21	STEAM		311I	Structures	4,096,077	2,717,547		1,378,531
22	STEAM		312I	Boiler Plant	76,455,057	34,070,059		42,384,998
23	STEAM		312IT	(Unit Train)	329,005	150,320		178,684
24	STEAM		314I	Turbogenerators	15,158,971	5,582,232		9,576,739
25	STEAM		315I	Access. Electric	8,494,977	3,650,534		4,844,443
26	STEAM		316I	Misc. Equipment	1,368,698	679,277		689,421
27			**IATAN 1**		**106,024,424**	**46,849,969**	**-**	**59,174,454**
28	STEAM		311I2	Structures	20,678,513	2,663,250		18,015,264
29	STEAM		311.05	Reg Plan Amort			3,544,751	(3,544,751)
30	STEAM		312I2	Boiler Plant	144,072,978	17,946,157		126,126,820
31	STEAM		312.05	Reg Plan Amort			23,321,791	(23,321,791)
32	STEAM		314I2	Turbogenerators	48,930,238	6,050,615		42,879,623
33	STEAM		314.05	Reg Plan Amort			8,319,550	(8,319,550)
34	STEAM		315I2	Access. Electric	12,506,401	1,552,301		10,954,099
35	STEAM		315.05	Reg Plan Amort			2,101,102	(2,101,102)
36	STEAM		316I2	Misc. Equipment	347,343	472,823		(125,481)
37	STEAM		316.05	Reg Plan Amort			25,758	(25,758)
38			**IATAN 2**		**226,535,472**	**28,685,146**	**37,312,953**	**160,537,373**
39			310IC		7,217	-		7,217
40	STEAM		311IC	Structures	15,841,683	1,008,815		14,832,868
41	STEAM		312IC	Boiler Plant	38,937,085	4,872,656		34,064,429
42	STEAM		314IC	Turbogenerators	1,294,040	121,694		1,172,347
43	STEAM		315IC	Access. Electric	4,821,624	471,535		4,350,088
44	STEAM		316IC	Misc. Equipment	695,702	33,821		661,882
45			**IATAN COMMON**		**61,597,351**	**6,508,520**	**-**	**55,088,831**
46			310P		956,529	-		956,529
47	STEAM		311P	Structures	20,567,779	2,829,391		17,738,388
48	STEAM		312P	Boiler Plant	53,909,728	7,730,914		46,178,814
49	STEAM		312PT	(Unit Train)	5,208,789	2,625,322		2,583,466
50	STEAM		314P	Turbogenerators	17,210,918	2,409,239		14,801,678
51	STEAM		315P	Access. Electric	5,406,008	884,060		4,521,948
52	STEAM		316P	Misc. Equipment	2,968,456	566,109		2,402,347
53			**PLUM POINT**		**106,228,207**	**17,045,035**	**-**	**89,183,171**
54			330	Land	226,488	-		226,488
55	HYDRO		331	Structures	811,148	317,353		493,795
56	HYDRO		332	Dams	3,418,630	1,522,763		1,895,868
57	HYDRO		333	Turbogenerators	4,482,395	739,577		3,742,817
58	HYDRO		334	Access. Electric	1,479,085	410,491		1,068,594
59	HYDRO		335	Misc. Equipment	651,456	224,387		427,069
60			**HYDRO**		**11,069,201**	**3,214,571**	**-**	**7,854,630**
61			340E	Land	163,097	-		163,097
62	OTHER		341E	Structures	2,315,557	1,596,001		719,557
63	OTHER		342E	Fuel Holders	1,292,806	1,406,650		(113,844)
64	OTHER		343E	Prime Movers	27,224,987	17,783,033		9,441,953
65	OTHER		344E	Generators	5,525,602	4,387,593		1,138,009
66	OTHER		345E	Access. Electric	2,180,466	1,416,519		763,947
67	OTHER		346E	Misc. Equipment	1,814,563	2,033,746		(219,183)

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/15	Accumulated Depreciation	Amortization	Net Plant Balance	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/16	Accumulated Depreciation	Amortization	Net Plant Balance
68		12-15 Plt in Svc Depr	**ENERGY CENTER**		**39,988,349**	**31,368,508**	**-**	**8,619,841**	12-16 Plt in Svc Depr	**ENERGY CENTER**		**38,766,788**	**26,696,283**	**-**	**12,070,505**
69	OTHER		341FT	Structures	1,133,884	180,449		953,435		341FT	Structures	1,133,884	206,892		926,991
70	OTHER		342FT	Fuel Holders	1,467,460	371,055		1,096,405		342FT	Fuel Holders	1,467,460	410,748		1,056,712
71	OTHER		343FT	Prime Movers	49,529,702	7,717,904		41,811,798		343FT	Prime Movers	48,794,677	8,071,211		40,723,466
72	OTHER		344FT	Generators	519,289	37,702		481,587		344FT	Generators	625,171	50,901		574,270
73	OTHER		345FT	Access. Electric	3,335,462	727,925		2,607,536		345FT	Access. Electric	3,337,033	811,769		2,525,264
74	OTHER		346FT	Misc. Equipment	1,063,704	248,574		815,131		346FT	Misc. Equipment	1,063,704	275,192		788,512
75			**ENERGY CENTER FT8**		**57,049,501**	**9,283,609**	**-**	**47,765,892**		**ENERGY CENTER FT8**		**56,421,930**	**9,826,715**	**-**	**46,595,215**
76			340	Land	253,184	-		253,184		340	Land	253,184	-		253,184
77			**RIVERTON COMMON**		**253,184**			**253,184**		**RIVERTON COMMON**		**253,184**			**253,184**
78	OTHER		341R	Structures	7,529,233	1,801,926		5,727,307		341R	Structures	7,739,286	1,991,653		5,747,633
79	OTHER		342R	Fuel Holders	456,988	237,148		219,840		342R	Fuel Holders	456,988	248,783		208,205
80	OTHER		343R	Prime Movers	6,722,820	3,324,489		3,398,331		343R	Prime Movers	7,173,886	3,472,082		3,701,804
81	OTHER		344R	Generators	1,764,497	914,363		850,134		344R	Generators	1,779,491	950,796		828,696
82	OTHER		345R	Access. Electric	1,452,687	602,395		850,292		345R	Access. Electric	1,492,271	597,307		894,964
83	OTHER		346R	Misc. Equipment	746,318	342,768		403,550		346R	Misc. Equipment	810,328	346,948		463,381
84			**RIVERTON 9, 10, 11**		**18,672,542**	**7,223,087**	**-**	**11,449,454**		**RIVERTON 9, 10, 11**		**19,452,251**	**7,607,568**	**-**	**11,844,683**
85	OTHER		341R12	Structures	494,249	51,539		442,710		341R12	Structures	17,597,678	270,553		17,327,125
86	OTHER		342R12	Fuel Holders	945,601	161,477		784,124		342R12	Fuel Holders	945,601	183,187		762,414
87	OTHER		343R12	Prime Movers	13,751,165	1,996,989		11,754,176		343R12	Prime Movers	150,948,003	3,983,048		146,964,955
88	OTHER		344R12	Generators	11,537,062	1,894,463		9,642,599		344R12	Generators	21,196,328	2,231,024		18,965,304
89	OTHER		345R12	Access. Electric	10,233,956	1,375,662		8,858,294		345R12	Access. Electric	26,623,995	1,840,484		24,783,510
90	OTHER		346R12	Misc. Equipment	1,484,187	351,419		1,132,768		346R12	Misc. Equipment	2,633,456	402,289		2,231,166
91			**RIVERTON UNIT 12**		**38,446,220**	**5,831,548**	**-**	**32,614,672**		**RIVERTON UNIT 12**		**219,945,061**	**8,910,585**	**-**	**211,034,475**
92			340S	Land	11,897	-		11,897		340S	Land	11,897	-		11,897
93	OTHER		341S	Structures	1,103,160	1,190,550		(87,390)		341S	Structures	1,103,160	944,823		158,338
94	OTHER		342S	Fuel Holders	3,187,313	2,169,272		1,018,041		342S	Fuel Holders	3,187,313	2,241,349		945,964
95	OTHER		343S	Prime Movers	26,308,743	13,111,769		13,196,973		343S	Prime Movers	26,390,894	13,844,182		12,546,712
96	OTHER		344S	Generators	7,049,204	4,458,416		2,590,787		344S	Generators	6,967,115	4,524,703		2,442,413
97	OTHER		345S	Access. Electric	3,078,861	1,735,869		1,342,992		345S	Access. Electric	3,078,977	1,809,288		1,269,689
98	OTHER		346S	Misc. Equipment	260,366	271,232		(10,866)		346S	Misc. Equipment	260,366	237,388		22,978
99			**STATE LINE UNIT 1**		**40,999,543**	**22,937,108**	**-**	**18,062,434**		**STATE LINE UNIT 1**		**40,999,722**	**23,601,733**	**-**	**17,397,990**
100	OTHER		341SC	Structures						341SC					
101	OTHER		342SC	Fuel Holders						342SC					
102	OTHER		343SC	Prime Movers						343SC					
103	OTHER		345SC	Access. Electric						345SC					
104	OTHER		346SC	Misc. Equipment						346SC					
105			**STATE LINE COMMON**							**STATE LINE COMMON**					
106			340C	Land	850,260	-		850,260		340C	Land	838,836	-		838,836
107	OTHER		341C	Structures	10,648,653	3,273,384		7,375,269		341C	Structures	10,654,662	3,498,528		7,156,134
108	OTHER		342C	Fuel Holders	409,439	1,632,929		(1,223,490)		342C	Fuel Holders	493,483	424,475		69,008
109	OTHER		343C	Prime Movers	107,313,145	29,329,039		77,984,106		343C	Prime Movers	106,982,137	30,545,891		76,436,246
110	OTHER		344C	Generators	30,362,332	5,347,177		25,015,155		344C	Generators	30,348,653	6,066,348		24,282,305
111	OTHER		345C	Access. Electric	8,293,831	2,758,905		5,534,926		345C	Access. Electric	8,406,250	2,943,674		5,462,577
112	OTHER		346C	Misc. Equipment	3,711,385	667,233		3,044,153		346C	Misc. Equipment	3,808,504	753,160		3,055,344
113			**STATE LINE CC**		**161,589,045**	**43,008,667**	**-**	**118,580,378**		**STATE LINE CC**		**161,532,525**	**44,232,074**	**-**	**117,300,451**
114			350	Land	11,925,628	-		11,925,628		350	Land	12,028,040	-		12,028,040
115	TRANSMISSION		352	Structures	2,865,262	1,358,134		1,507,127		352	Structures	3,024,247	1,416,481		1,607,766
116	TRANSMISSION		352I	Structures (Iatan)	23,013	23,161		(148)		352I	Structures (Iatan)	23,013	44,417		(21,404)
117	TRANSMISSION		353	Station Equip.	132,459,632	43,120,021		89,339,611		353	Station Equip.	143,893,122	44,828,296		99,064,826
118	TRANSMISSION		353I	Station Eq. (Iatan)	529,906	502,363		27,543		353I	Station Eq. (Iatan)	529,906	522,876		7,030
119	TRANSMISSION		354	Towers & Fixtures	2,136,321	904,956		1,231,365		354	Towers & Fixtures	1,782,962	936,501		846,461
120	TRANSMISSION		355	Poles & Fixtures	86,667,843	23,926,996		62,740,847		355	Poles & Fixtures	89,437,886	24,552,275		64,885,612
121	TRANSMISSION		356	OH Conductor	79,429,952	25,212,436		54,217,516		356	OH Conductor	87,632,213	25,211,539		62,420,674
122			**TRANSMISSION**		**316,037,557**	**95,048,068**	**-**	**220,989,489**		**TRANSMISSION**		**338,351,390**	**97,512,385**	**-**	**240,839,004**
123			360	Land	3,995,089	-		3,995,089		360	Land	4,265,548	-		4,265,548
124	DISTRIBUTION		361	Structures	27,397,169	5,430,683		21,966,485		361	Structures	26,764,178	4,849,735		21,914,443
125	DISTRIBUTION		362	Station Equip.	105,145,313	36,717,734		68,427,579		362	Station Equip.	109,746,559	37,835,288		71,911,272
126	DISTRIBUTION		364	Poles & Fixtures	187,899,093	93,218,897		94,680,196		364	Poles & Fixtures	197,108,766	97,481,336		99,627,430
127	DISTRIBUTION		365	OH Conductor	196,731,664	85,435,566		111,296,099		365	OH Conductor	204,080,319	91,233,565		112,846,754
128	DISTRIBUTION		366	UG Conduit	38,986,890	16,867,109		22,119,782		366	UG Conduit	40,557,307	18,215,092		22,342,215
129	DISTRIBUTION		367	UG Conductor	60,713,371	31,659,351		29,054,019		367	UG Conductor	63,755,405	33,546,106		30,209,300
130	DISTRIBUTION		368	Transformers	110,407,244	40,230,795		70,176,449		368	Transformers	114,709,243	42,244,763		72,464,479
131	DISTRIBUTION		369	Services	78,645,963	53,038,844		25,607,119		369	Services	81,029,532	56,627,155		24,402,377
132	DISTRIBUTION		370	Meters	23,335,929	8,119,940		15,215,989		370	Meters	24,632,289	8,654,544		15,977,745
133	DISTRIBUTION		371	Private Lights	16,968,401	12,286,788		4,681,612		371	Private Lights	16,996,918	12,715,309		4,281,609

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/17	Accumulated Depreciation	Amortization	Net Plant Balance	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/17	Accumulated Depreciation	Amortization	Net Plant Balance
68		12-17 Plt in Svc Depr	**ENERGY CENTER**		**39,759,304**	**27,967,526**	**-**	**11,791,778**	06-17 Plt in Svc Depr	**ENERGY CENTER**		**38,937,362**	**27,354,023**	**-**	**11,583,340**
69	OTHER		341FT	Structures	1,125,893	227,019		898,874		341FT	Structures	1,122,352	212,226		910,126
70	OTHER		342FT	Fuel Holders	1,404,451	453,901		950,550		342FT	Fuel Holders	1,467,460	432,562		1,034,898
71	OTHER		343FT	Prime Movers	49,074,508	8,771,575		40,302,933		343FT	Prime Movers	49,761,462	8,741,718		41,019,744
72	OTHER		344FT	Generators	625,119	69,176		555,943		344FT	Generators	625,171	60,035		565,136
73	OTHER		345FT	Access. Electric	3,409,993	911,670		2,498,323		345FT	Access. Electric	3,337,033	862,397		2,474,636
74	OTHER		346FT	Misc. Equipment	1,041,864	279,252		762,612		346FT	Misc. Equipment	1,059,316	286,266		773,049
75			**ENERGY CENTER FT8**		**56,681,828**	**10,712,593**	**-**	**45,969,235**		**ENERGY CENTER FT8**		**57,372,794**	**10,595,204**	**-**	**46,777,590**
76			340	Land	253,184	-		253,184		340	Land	253,184	-		253,184
77			**RIVERTON COMMON**		**253,184**			**253,184**		**RIVERTON COMMON**		**253,184**	**-**	**-**	**253,184**
78	OTHER		341R	Structures	8,082,297	2,311,490		5,770,808		341R	Structures	7,824,787	2,150,154		5,674,633
79	OTHER		342R	Fuel Holders	533,729	263,384		270,345		342R	Fuel Holders	456,988	255,790		201,198
80	OTHER		343R	Prime Movers	7,045,710	3,504,535		3,541,176		343R	Prime Movers	7,206,390	3,559,409		3,646,981
81	OTHER		344R	Generators	1,779,491	992,426		787,065		344R	Generators	1,779,491	971,607		807,885
82	OTHER		345R	Access. Electric	1,557,355	647,475		909,880		345R	Access. Electric	1,492,271	623,568		868,704
83	OTHER		346R	Misc. Equipment	946,634	374,950		571,684		346R	Misc. Equipment	831,749	360,617		471,132
84			**RIVERTON 9, 10, 11**		**19,945,217**	**8,094,260**	**-**	**11,850,958**		**RIVERTON 9, 10, 11**		**19,591,677**	**7,921,145**	**-**	**11,670,532**
85	OTHER		341R12	Structures	17,763,293	850,302		16,912,991		341R12	Structures	17,744,267	629,425		17,114,842
86	OTHER		342R12	Fuel Holders	945,601	204,555		741,046		342R12	Fuel Holders	945,601	193,875		751,726
87	OTHER		343R12	Prime Movers	151,225,049	7,356,339		143,868,710		343R12	Prime Movers	151,144,986	5,696,936		145,448,050
88	OTHER		344R12	Generators	21,353,322	2,673,869		18,679,453		344R12	Generators	21,200,873	2,452,347		18,748,526
89	OTHER		345R12	Access. Electric	26,636,252	2,510,884		24,125,368		345R12	Access. Electric	26,631,707	2,175,746		24,455,960
90	OTHER		346R12	Misc. Equipment	2,633,996	464,776		2,169,221		346R12	Misc. Equipment	2,633,996	433,542		2,200,454
91			**RIVERTON UNIT 12**		**220,557,514**	**14,060,725**	**-**	**206,496,789**		**RIVERTON UNIT 12**		**220,301,430**	**11,581,871**	**-**	**208,719,559**
92			340S	Land	11,897	-		11,897		340S	Land	11,897	-		11,897
93	OTHER		341S	Structures	1,103,160	964,638		138,522		341S	Structures	1,103,160	954,730		148,430
94	OTHER		342S	Fuel Holders	3,187,313	2,298,938		888,374		342S	Fuel Holders	3,187,313	2,270,169		917,144
95	OTHER		343S	Prime Movers	24,869,219	12,762,675		12,106,544		343S	Prime Movers	26,438,225	14,041,340		12,396,885
96	OTHER		344S	Generators	4,941,133	2,591,503		2,349,630		344S	Generators	6,967,115	4,572,257		2,394,859
97	OTHER		345S	Access. Electric	2,845,427	1,500,109		1,345,318		345S	Access. Electric	3,145,275	1,840,953		1,304,323
98	OTHER		346S	Misc. Equipment	148,714	102,619		46,094		346S	Misc. Equipment	290,003	240,175		49,828
99			**STATE LINE UNIT 1**		**37,106,863**	**20,220,482**	**-**	**16,886,380**		**STATE LINE UNIT 1**		**41,142,989**	**23,919,624**	**-**	**17,223,365**
100	OTHER		341SC	Structures	3,009,642	1,153,934		1,855,709		341SC	Structures	2,969,463	1,162,441		1,807,023
101	OTHER		342SC	Fuel Holders	226,749	230,792		(4,042)		342SC	Fuel Holders	226,749	228,366		(1,617)
102	OTHER		343SC	Prime Movers	631,534	15,393		616,142		343SC	Prime Movers	516,075	9,282		506,793
103	OTHER		345SC	Access. Electric	47,445	23,728		23,718		345SC	Access. Electric	47,445	23,224		24,221
104	OTHER		346SC	Misc. Equipment	1,019,713	180,235		839,479		346SC	Misc. Equipment	1,022,552	167,567		854,985
105			**STATE LINE COMMON**		**4,935,085**	**1,604,080**	**-**	**3,331,005**		**STATE LINE COMMON**		**4,782,286**	**1,590,880**	**-**	**3,191,406**
106			340C	Land	838,836	-		838,836		340C	Land	838,836	-		838,836
107	OTHER		341C	Structures	7,889,314	2,506,504		5,382,811		341C	Structures	7,906,290	2,443,649		5,462,641
108	OTHER		342C	Fuel Holders	266,498	204,238		62,259		342C	Fuel Holders	266,498	201,388		65,110
109	OTHER		343C	Prime Movers	106,731,350	32,141,419		74,589,931		343C	Prime Movers	106,772,349	31,459,076		75,313,273
110	OTHER		344C	Generators	30,347,252	6,624,051		23,723,201		344C	Generators	30,230,515	6,292,191		23,938,324
111	OTHER		345C	Access. Electric	8,463,365	3,099,427		5,363,937		345C	Access. Electric	8,411,912	3,009,683		5,402,229
112	OTHER		346C	Misc. Equipment	2,726,090	583,661		2,142,429		346C	Misc. Equipment	2,760,255	593,433		2,166,822
113			**STATE LINE CC**		**157,262,705**	**45,159,301**	**-**	**112,103,404**		**STATE LINE CC**		**157,186,655**	**43,999,420**	**-**	**113,187,235**
114			350	Land	11,923,369	-		11,923,369		350	Land	11,928,014	-		11,928,014
115	TRANSMISSION		352	Structures	2,883,747	1,442,016		1,441,732		352	Structures	3,089,447	1,429,083		1,660,365
116	TRANSMISSION		352I	Structures (Iatan)	23,013	44,872		(21,859)		352I	Structures (Iatan)	23,013	44,645		(21,632)
117	TRANSMISSION		353	Station Equip.	161,644,682	45,496,015		116,148,667		353	Station Equip.	150,680,410	45,443,010		105,237,400
118	TRANSMISSION		353I	Station Eq. (Iatan)	602,064	528,089		73,976		353I	Station Eq. (Iatan)	521,689	519,623		2,067
119	TRANSMISSION		354	Towers & Fixtures	1,817,799	966,597		851,202		354	Towers & Fixtures	1,817,409	951,457		865,952
120	TRANSMISSION		355	Poles & Fixtures	90,738,373	26,931,176		63,807,198		355	Poles & Fixtures	89,555,957	25,779,383		63,776,574
121	TRANSMISSION		356	OH Conductor	90,058,894	26,414,186		63,644,707		356	OH Conductor	88,632,128	25,705,808		62,926,321
122			**TRANSMISSION**		**359,691,942**	**101,822,951**	**-**	**257,868,991**		**TRANSMISSION**		**346,248,069**	**99,873,008**	**-**	**246,375,061**
123			360	Land	4,128,843	-		4,128,843		360	Land	4,128,843	-		4,128,843
124	DISTRIBUTION		361	Structures	26,143,005	5,214,694		20,928,310		361	Structures	26,407,748	4,989,837		21,417,911
125	DISTRIBUTION		362	Station Equip.	124,780,102	39,354,264		85,425,838		362	Station Equip.	120,209,495	38,409,651		81,799,844
126	DISTRIBUTION		364	Poles & Fixtures	208,028,482	101,499,908		106,528,574		364	Poles & Fixtures	202,577,852	100,285,140		102,292,712
127	DISTRIBUTION		365	OH Conductor	210,763,681	97,390,446		113,373,235		365	OH Conductor	208,040,103	94,363,801		113,676,302
128	DISTRIBUTION		366	UG Conduit	43,013,010	19,087,415		23,925,595		366	UG Conduit	41,401,315	18,498,598		22,902,717
129	DISTRIBUTION		367	UG Conductor	65,807,157	35,379,698		30,427,459		367	UG Conductor	64,311,761	34,430,623		29,881,138
130	DISTRIBUTION		368	Transformers	120,421,884	43,886,741		76,535,143		368	Transformers	118,274,052	43,540,972		74,733,080
131	DISTRIBUTION		369	Services	84,450,222	59,988,024		24,462,198		369	Services	82,310,827	58,333,160		23,977,667
132	DISTRIBUTION		370	Meters	24,570,957	7,438,035		17,132,921		370	Meters	24,996,620	8,718,544		16,278,076
133	DISTRIBUTION		371	Private Lights	17,104,341	13,112,090		3,992,251		371	Private Lights	17,149,964	13,045,768		4,104,196

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/18	Accumulated Depreciation	Amortization	Net Plant Balance
68		06-18 Plt in Svc Depr	**ENERGY CENTER**		**40,517,077**	**28,623,541**	**-**	**11,893,537**
69	OTHER		341FT	Structures	1,125,893	243,841		882,052
70	OTHER		342FT	Fuel Holders	1,404,451	474,754		929,697
71	OTHER		343FT	Prime Movers	49,048,628	9,410,107		39,638,521
72	OTHER		344FT	Generators	625,119	78,336		546,783
73	OTHER		345FT	Access. Electric	3,405,450	959,195		2,446,255
74	OTHER		346FT	Misc. Equipment	1,041,864	294,395		747,469
75			**ENERGY CENTER FT8**		**56,651,405**	**11,460,629**	**-**	**45,190,776**
76			340	Land	253,184	-		253,184
77			**RIVERTON COMMON**		**253,184**			**253,184**
78	OTHER		341R	Structures	8,070,145	2,449,511		5,620,634
79	OTHER		342R	Fuel Holders	554,012	271,784		282,228
80	OTHER		343R	Prime Movers	7,053,439	3,590,513		3,462,926
81	OTHER		344R	Generators	1,779,491	1,013,267		766,224
82	OTHER		345R	Access. Electric	1,551,993	674,874		877,119
83	OTHER		346R	Misc. Equipment	1,035,638	386,682		648,956
84			**RIVERTON 9, 10, 11**		**20,044,718**	**8,386,631**	**-**	**11,658,087**
85	OTHER		341R12	Structures	17,818,456	1,071,531		16,746,924
86	OTHER		342R12	Fuel Holders	945,601	215,218		730,383
87	OTHER		343R12	Prime Movers	151,342,736	9,072,047		142,270,689
88	OTHER		344R12	Generators	21,353,322	2,896,562		18,456,759
89	OTHER		345R12	Access. Electric	26,519,404	2,728,057		23,791,348
90	OTHER		346R12	Misc. Equipment	2,633,996	495,968		2,138,029
91			**RIVERTON UNIT 12**		**220,613,515**	**16,479,383**	**-**	**204,134,132**
92			340S	Land	11,897	-		11,897
93	OTHER		341S	Structures	1,109,083	974,222		134,861
94	OTHER		342S	Fuel Holders	3,187,313	2,327,583		859,730
95	OTHER		343S	Prime Movers	24,934,047	12,969,502		11,964,544
96	OTHER		344S	Generators	4,981,718	2,625,264		2,356,454
97	OTHER		345S	Access. Electric	2,845,427	1,529,149		1,316,278
98	OTHER		346S	Misc. Equipment	148,714	104,675		44,039
99			**STATE LINE UNIT 1**		**37,218,198**	**20,530,395**	**-**	**16,687,803**
100	OTHER		341SC	Structures	3,053,894	1,186,838		1,867,055
101	OTHER		342SC	Fuel Holders	226,749	233,216		(6,466)
102	OTHER		343SC	Prime Movers	631,509	21,740		609,769
103	OTHER		345SC	Access. Electric	198,310	24,474		173,836
104	OTHER		346SC	Misc. Equipment	990,568	184,176		806,393
105			**STATE LINE COMMON**		**5,101,030**	**1,650,443**		**3,450,586**
106			340C	Land	838,836	-		838,836
107	OTHER		341C	Structures	7,889,706	2,585,629		5,304,077
108	OTHER		342C	Fuel Holders	266,498	207,087		59,411
109	OTHER		343C	Prime Movers	107,995,672	33,004,046		74,991,627
110	OTHER		344C	Generators	30,294,250	6,967,266		23,326,985
111	OTHER		345C	Access. Electric	8,625,382	3,189,314		5,436,068
112	OTHER		346C	Misc. Equipment	2,760,623	623,388		2,137,236
113			**STATE LINE CC**		**158,670,967**	**46,576,730**	**-**	**112,094,238**
114			350	Land	11,923,369	-		11,923,369
115	TRANSMISSION		352	Structures	3,252,272	1,443,193		1,809,078
116	TRANSMISSION		352I	Structures (Iatan)	23,013	45,100		(22,087)
117	TRANSMISSION		353	Station Equip.	163,351,416	45,652,842		117,698,574
118	TRANSMISSION		353I	Station Eq. (Iatan)	603,764	533,731		70,032
119	TRANSMISSION		354	Towers & Fixtures	1,921,183	979,199		941,983
120	TRANSMISSION		355	Poles & Fixtures	95,285,851	28,335,419		66,950,431
121	TRANSMISSION		356	OH Conductor	96,324,512	27,215,556		69,108,956
122			**TRANSMISSION**		**372,685,379**	**104,205,042**	**-**	**268,480,337**
123			360	Land	4,626,086	-		4,626,086
124	DISTRIBUTION		361	Structures	26,551,179	5,389,058		21,162,121
125	DISTRIBUTION		362	Station Equip.	133,321,697	40,093,785		93,227,912
126	DISTRIBUTION		364	Poles & Fixtures	212,240,386	104,547,454		107,692,932
127	DISTRIBUTION		365	OH Conductor	213,434,101	100,964,312		112,469,789
128	DISTRIBUTION		366	UG Conduit	45,244,141	19,799,229		25,444,913
129	DISTRIBUTION		367	UG Conductor	66,852,734	36,512,680		30,340,054
130	DISTRIBUTION		368	Transformers	123,242,975	45,208,329		78,034,645
131	DISTRIBUTION		369	Services	86,058,629	61,886,629		24,172,000
132	DISTRIBUTION		370	Meters	24,593,635	7,661,365		16,932,270
133	DISTRIBUTION		371	Private Lights	17,772,916	13,571,938		4,200,978

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/15	Accumulated Depreciation	Amortization	Net Plant Balance	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/16	Accumulated Depreciation	Amortization	Net Plant Balance
134	DISTRIBUTION	12-15 Plt in Svc Depr	373	Street Lights	19,151,358	4,919,032		14,232,327	12-16 Plt in Svc Depr	373	Street Lights	19,387,155	5,145,033		14,242,123
135	DISTRIBUTION		375	Charging Stations						375	Charging Stations	11,439	505		10,934
136			**DISTRIBUTION**		**869,377,485**	**387,924,739**	**-**	**481,452,746**		**DISTRIBUTION**		**903,044,659**	**408,548,430**	**-**	**494,496,229**
137			389	Land	659,081	-		659,081		389	Land	1,160,224	-		1,160,224
138	GENERAL		390	Structure	11,005,100	6,415,295		4,589,805		390	Structure	11,439,576	6,694,077		4,745,499
139	GENERAL		391	Furniture	6,229,654	2,097,995		4,131,659		391	Furniture	6,264,990	2,375,132		3,889,858
140	GENERAL		391C	Computer Equip.	14,044,017	10,233,721		3,810,297		391C	Computer Equip.	14,110,342	11,079,039		3,031,303
141	GENERAL		392	Transport. Equip.	12,632,828	6,942,063		5,690,765		392	Transport. Equip.	13,682,922	7,001,497		6,681,424
142	GENERAL		393	Stores Equip.	831,566	387,978		443,588		393	Stores Equip.	834,611	384,453		450,158
143	GENERAL		394	Tools	6,396,061	3,527,614		2,868,447		394	Tools	6,809,051	3,800,385		3,008,667
144	GENERAL		395	Lab Equipment	1,343,198	861,756		481,442		395	Lab Equipment	1,601,176	897,553		703,623
145	GENERAL		396	Power Op. Equip.	17,981,052	7,672,706		10,308,345		396	Power Op. Equip.	18,680,698	7,125,175		11,555,524
146	GENERAL		397	Communication	12,118,205	6,354,716		5,763,489		397	Communication	11,783,559	6,247,668		5,535,891
147	GENERAL		398	Misc. Equipment	276,456	181,030		95,427		398	Misc. Equipment	283,621	192,150		91,470
148			**GENERAL**		**83,517,218**	**44,674,873**	**-**	**38,842,345**		**GENERAL**		**86,650,770**	**45,797,128**	**-**	**40,853,642**
149			**ELECTRIC UTILITY**		**$ 2,448,006,875**	**$ 767,728,571**	**$ 52,883,968**	**$ 1,627,394,336**		**ELECTRIC UTILITY**		**$ 2,692,275,633**	**$ 822,546,102**	**$ 54,221,251**	**$ 1,815,508,280**
						WP-5.1 Depr Detail	WP-5.1 Depr Detail						WP-5.1 Depr Detail	WP-5.1 Depr Detail	

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 12/31/17	Accumulated Depreciation	Amortization	Net Plant Balance
134	DISTRIBUTION	12-17 Plt in Svc Depr	373	Street Lights	19,717,509	5,041,833		14,675,675
135	DISTRIBUTION		375	Charging Stations	151,313	3,177		148,135
136			**DISTRIBUTION**		**949,080,504**	**427,396,326**	**-**	**521,684,177**
137			389	Land	1,057,907	-		1,057,907
138	GENERAL		390	Structure	11,697,714	6,940,901		4,756,813
139	GENERAL		391	Furniture	6,266,370	2,644,677		3,621,693
140	GENERAL		391C	Computer Equip.	14,596,362	11,367,236		3,229,125
141	GENERAL		392	Transport. Equip.	14,341,658	7,935,351		6,406,307
142	GENERAL		393	Stores Equip.	855,334	406,253		449,081
143	GENERAL		394	Tools	6,974,821	3,975,735		2,999,086
144	GENERAL		395	Lab Equipment	1,985,646	938,641		1,047,005
145	GENERAL		396	Power Op. Equip.	18,252,136	7,970,305		10,281,830
146	GENERAL		397	Communication	11,876,741	6,747,358		5,129,383
147	GENERAL		398	Misc. Equipment	277,439	196,455		80,984
148			**GENERAL**		**88,182,128**	**49,122,913**	**-**	**39,059,214**
149			**ELECTRIC UTILITY**		**$ 2,768,491,782**	**$ 867,831,720**	**$ 56,242,585**	**$ 1,847,748,482**
						WP-5.1 Depr Detail	WP-5.1 Depr Detail	

Line No.	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/17	Accumulated Depreciation	Amortization	Net Plant Balance
134	06-17 Plt in Svc Depr	373	Street Lights	19,650,995	5,291,094		14,359,901
135		375	Charging Stations	11,439	791		10,648
136		**DISTRIBUTION**		**929,471,014**	**419,907,978**	**-**	**509,563,036**
137		389	Land	1,160,224	-		1,160,224
138		390	Structure	11,435,789	6,792,553		4,643,236
139		391	Furniture	6,284,658	2,507,848		3,776,809
140		391C	Computer Equip.	14,993,651	11,737,764		3,255,886
141		392	Transport. Equip.	14,080,418	7,474,486		6,605,932
142		393	Stores Equip.	834,611	394,298		440,313
143		394	Tools	6,763,252	3,900,407		2,862,845
144		395	Lab Equipment	1,628,573	916,640		711,934
145		396	Power Op. Equip.	18,306,794	7,620,526		10,686,268
146		397	Communication	11,816,450	6,507,329		5,309,121
147		398	Misc. Equipment	283,621	197,395		86,226
148		**GENERAL**		**87,588,039**	**48,049,245**	**-**	**39,538,794**
149		**ELECTRIC UTILITY**		**$ 2,734,257,011**	**$ 849,718,700**	**$ 54,465,847**	**$ 1,830,072,464**
					WP-5.1 Depr Detail	WP-5.1 Depr Detail	

Line No.	Type	Reference	DEPR GRP	FERC DESCR	PLANT IN SVC @ 6/30/18	Accumulated Depreciation	Amortization	Net Plant Balance
134	DISTRIBUTION	06-18 Plt in Svc Depr	373	Street Lights	20,088,987	5,365,363		14,723,624
135	DISTRIBUTION		375	Charging Stations	151,313	6,960		144,352
136			**DISTRIBUTION**		**974,178,778**	**441,007,102**	**-**	**533,171,676**
137			389	Land	1,057,907	-		1,057,907
138	GENERAL		390	Structure	11,914,537	7,096,789		4,817,748
139	GENERAL		391	Furniture	6,283,777	2,777,985		3,505,792
140	GENERAL		391C	Computer Equip.	15,127,945	12,030,647		3,097,298
141	GENERAL		392	Transport. Equip.	14,599,573	8,360,115		6,239,458
142	GENERAL		393	Stores Equip.	865,162	418,439		446,723
143	GENERAL		394	Tools	7,097,214	4,146,997		2,950,217
144	GENERAL		395	Lab Equipment	1,994,597	962,133		1,032,465
145	GENERAL		396	Power Op. Equip.	18,354,751	8,460,466		9,894,285
146	GENERAL		397	Communication	11,909,664	7,009,743		4,899,921
147	GENERAL		398	Misc. Equipment	277,238	201,617		75,621
148			**GENERAL**		**89,482,366**	**51,464,931**	**-**	**38,017,436**
149			**ELECTRIC UTILITY**		**$ 2,818,371,221**	**$ 902,705,962**	**$ 58,150,304**	**$ 1,857,514,955**
						WP-5.1 Depr Detail	WP-5.1 Depr Detail	

Test Year Ending June 30, 2018

				Total Company			Kansas		
Line No.	GL Account	Description	Reference	Ending Balance	Pro Forma Adjustments	Adjusted Ending Balance	Ending Balance	Pro Forma Adjustments	Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h)	(i) = (g) + (h)
1	165100	Prepayments - Insurance	WP Insurance Detail	$ 1,123,977	$ 449,220	$ 1,573,197	$ 56,367	$ 22,391	$ 78,759
2	165200	Prepayments - Interest	WP Interest Detail	1,623	(122)	1,501	81	(6)	75
3	165300	Prepayments-Other	WP Other Detail	1,022,485	(335,110)	687,376	51,277	(16,930)	34,347
4	165350	Prepayments-Wrking Funds Iatan	WP Other Detail	1,636,423	(373,685)	1,262,738	82,066	(18,940)	63,127
5	165351	Prepmts-Wrking Funds PlumPoint	WP Other Detail	857,280	(132,899)	724,381	42,992	(6,769)	36,223
6	165352	Prepayments-KCP&L Land Lease	WP Other Detail	136,276	(19,484)	116,792	6,834	(994)	5,840
7	165400	Prepayments - Fuel	WP Fuel Detail	1,248,102	14,258	1,262,360	62,592	563	63,155
8	165500	Prepaid Purchased Power	WP Fuel Detail	1,329,583	(101,082)	1,228,501	66,678	(5,231)	61,447
9	165600	Prepayments - Plum Point	WP Other Detail	274,837	179,248	454,086	13,783	8,956	22,739
10	165800	Prepayments - Fleet Card	WP Other Detail	89,672	(57,286)	32,386	4,497	(2,884)	1,613
11	165900	Prepmts Riverton Def Mtce	WP Other Detail	430,956	(73,535)	357,420	21,612	(3,740)	17,872
12		Total Prepayments		$ 8,151,213	$ (450,476)	$ 7,700,737	$ 408,782	$ (23,585)	$ 385,197

Test Year Ending June 30, 2018

			Total Company			Kansas		
Line No.	GL Account	Description	Prepayments 13 Month Average	TDC Adjustment	Total Adjustments	Prepayments 13 Month Average	TDC Adjustment	Total Adjustments
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1		**Adjustment No.**	**ADJ-21**	**ADJ-17**		**ADJ-21**	**ADJ-17**	
2	165100	Prepayments - Insurance	$ 623,463	$ (174,243)	$ 449,220	$ 31,267	$ (8,875)	$ 22,391
3	165200	Prepayments - Interest	130	(252)	(122)	7	(13)	(6)
4	165300	Prepayments-Other	(176,600)	(158,510)	(335,110)	(8,856)	(8,074)	(16,930)
5	165350	Prepayments-Wrking Funds Iatan	(120,000)	(253,685)	(373,685)	(6,018)	(12,922)	(18,940)
6	165351	Prepmts-Wrking Funds PlumPoint	-	(132,899)	(132,899)	-	(6,769)	(6,769)
7	165352	Prepayments-KCP&L Land Lease	1,642	(21,126)	(19,484)	82	(1,076)	(994)
8	165400	Prepayments - Fuel	207,744	(193,486)	14,258	10,418	(9,855)	563
9	165500	Prepaid Purchased Power	105,035	(206,117)	(101,082)	5,268	(10,499)	(5,231)
10	165600	Prepayments - Plum Point	221,855	(42,606)	179,248	11,126	(2,170)	8,956
11	165800	Prepayments - Fleet Card	(43,385)	(13,901)	(57,286)	(2,176)	(708)	(2,884)
12	165900	Prepmts Riverton Def Mtce	(6,727)	(66,808)	(73,535)	(337)	(3,403)	(3,740)
13		Total Prepayments	$ 813,157	$ (1,263,633)	$ (450,476)	$ 40,780	$ (64,364)	$ (23,585)

Test Year Ending June 30, 2018

			Total Company			Kansas		
Line No.	**Description**	**Reference**	**Ending Balance**	**Pro Forma Adjustments**	**Adjusted Ending Balance**	**Ending Balance**	**Pro Forma Adjustments**	**Adjusted Ending Balance**
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Fuel	**WP-6.2 Fuel**	$ 21,044,298	$ (1,169,952)	$ 19,874,346	$ 948,712	$ (52,833)	$ 895,879
2	Other Materials	**WP-6.2 OPM**	6,880,312	(887,374)	5,992,938	326,230	(42,106)	284,125
3	Total Production		27,924,610	(2,057,326)	25,867,284	1,274,943	(94,939)	1,180,004
4	Transmission And Distribution	**WP-6.2T&D Materials**	26,066,348	(2,508,597)	23,557,751	1,433,403	(138,085)	1,295,318
5	Clearing Account Materials	**WP-6.2 CA Materials**	294,552	(30,827)	263,725	14,772	(1,547)	13,224
6	Total Materials and Supplies		$ 54,285,510	$ (4,596,750)	$ 49,688,760	$ 2,723,117	$ (234,571)	$ 2,488,546

Test Year Ending June 30, 2018

			Total Company				Kansas			
Line No.	**GL Account**	**Description**	**Water Inventory Adjustment**	**Materials and Supplies 13 Month Average**	**TDC Adjustment**	**Total Adjustments**	**Water Inventory Adjustment**	**Materials and Supplies 13 Month Average**	**TDC Adjustment**	**Total Adjustments**
	(a)	(b)	(c)	(d)	(e)	(f) = SUM (c) through (e)	(g)	(h)	(i)	(j) = SUM (g) through (i)
1		**Adjustment Number**	**ADJ-4**	**ADJ-22**	**ADJ-17**		**ADJ-4**	**ADJ-22**	**ADJ-17**	
FUEL										
2	151058	Maintenance Of Railroad	$ -	$ (42)	$ (3)	$ (45)	$ -	$ (2)	$ (0)	$ (2)
3	151059	Rail Car Maintenance		(79)	-	(79)		(4)	-	(4)
4	151060	Lease of Railcars		0	-	0		0	-	0
5	151100	Coal		(740,107)	(653,376)	(1,393,484)		(33,365)	(29,508)	(62,873)
6	151101	KCS Freight Adjustments		(3,401)	-	(3,401)		(153)	-	(153)
7	151130	Dep-Plum Point Unit Train		535,081	(1,473)	533,607		24,122	(67)	24,056
8	151200	Distillate Oil		72,921	(463,549)	(390,628)		3,287	(20,935)	(17,647)
9	151300	Tires		5,682	-	5,682		256	-	256
10	151548	Natural Gas - Park and Loan		75,757	-	75,757		3,415	-	3,415
11	152057	Fuel Stock Expense - Coal		1,386	-	1,386		62	-	62
12	152057	Fuel Expense Undist - Coal:		1,253	-	1,253		56	-	56
13		Total Fuel Test Year End:	-	(51,550)	(1,118,402)	(1,169,952)	-	(2,324)	(50,509)	(52,833)
OTHER PRODUCTION MATERIALS										
14	154910	Generation Parts & Mat-Elect		(617,788)	(236,713)	(854,500)		(29,292)	(11,244)	(40,536)
15	154911	SLCC Inv Cr-WGI Portion		261,345	95,985	357,330		12,392	4,559	16,951
16	154950	Ammonia Inventory		5,384	(392)	4,992		255	(19)	237
17	154951	Limestone Inventory		(7,312)	(1,253)	(8,565)		(347)	(60)	(406)
18	154952	Activated Carbon Inventory		663	(830)	(167)		31	(39)	(8)
19	154980	Stock Material - Iatan		(230,368)	(190,504)	(420,872)		(10,923)	(9,049)	(19,972)
20	154990	Inventory - Plum Point		59,362	(31,948)	27,414		2,815	(1,518)	1,297
21	158100	Emission Allowance Inventory		6,995	-	6,995		332	-	332
22		Total OPM Test Year End	-	(521,719)	(365,655)	(887,374)	-	(24,737)	(17,368)	(42,106)
T&D MATERIALS										
23	154000	Material	(49,016)	(1,053,621)	(1,344,798)	(2,447,434)	(2,695)	(57,939)	(74,083)	(134,717)
24	154100	Minor Material Undistributed		19,485	(36,864)	(17,379)		1,072	(2,031)	(959)
25	154700	Bulk Fuel Inventory - Kodiak		(40,146)	(3,638)	(43,784)		(2,208)	(200)	(2,408)
26		Total T&D Test Year End	(49,016)	(1,074,281)	(1,385,300)	(2,508,597)	(2,695)	(59,075)	(76,314)	(138,085)
CLEARING ACCOUNTS										
27	184015	IM SPP Clearing Account		0	-	0		0	-	0
28	184016	Payroll Clearing - Ceridian		(6,108)	-	(6,108)		(306)	-	(306)
29	184169	Underground Transformers - New		-	(28)	(28)		-	(1)	(1)
30	184230	Cellular Phone Expenses		-	(196)	(196)		-	(10)	(10)
31	184242	Pbx Switchboard		178	-	178		9	-	9
32	184243	Telephone Exp-Bld Serv		(6,095)	-	(6,095)		(306)	-	(306)
33	184311	Veh Maint-Cars		599	(0)	599		30	(0)	30
34	184312	Veh Maint-1/2 Ton Trucks		518	(0)	517		26	(0)	26
35	184313	Veh Maint-3/4 1 & 1 1/2 Ton		2,379	(2)	2,377		119	(0)	119
36	184314	Veh Maint-2 2 1/2 3 & Flatbeds		8	-	8		0	-	0
37	184321	Veh Maint - Line Trucks		6	(0)	6		0	(0)	0

Test Year Ending June 30, 2018

Line No.	GL Account	Description	Total Company: Water Inventory Adjustment	Total Company: Materials and Supplies 13 Month Average	Total Company: TDC Adjustment	Total Company: Total Adjustments	Kansas: Water Inventory Adjustment	Kansas: Materials and Supplies 13 Month Average	Kansas: TDC Adjustment	Kansas: Total Adjustments
	(a)	(b)	(c)	(d)	(e)	(f) = SUM (c) through (e)	(g)	(h)	(i)	(j) = SUM (g) through (i)
1		**Adjustment Number**	**ADJ-4**	**ADJ-22**	**ADJ-17**		**ADJ-4**	**ADJ-22**	**ADJ-17**	
38	184322	Veh Maint-Aerial Basket Trucks		5	-	5		0	-	0
39	184323	Veh Maint - Crane Trucks		-	(27)	(27)		-	(1)	(1)
40	184331	Mgmt & Admin - Transp		1,402	(2)	1,400		70	(0)	70
41	184341	Dot Expenses (State & Federal)		474	-	474		24	-	24
42	184342	Cdl License & Physicals		(469)	-	(469)		(24)	-	(24)
43	184392	Transp Clring -Light Duty-Gas		(174)	(16)	(189)		(9)	(1)	(9)
44	184413	FAS87 Pension - Capitalized		(11,052)	-	(11,052)		(554)	-	(554)
45	184416	Healthcare - Capitalized		17,372	-	17,372		871	-	871
46	184422	Admin & Gen Clearing - EDG		2	-	2		0	-	0
47	184490	Clearing FICA Asset Portion		(2,242)	-	(2,242)		(112)	-	(112)
48	184491	Clear FUI to Assets		23	-	23		1	-	1
49	184492	Clear SUI to Assets		(47)	-	(47)		(2)	-	(2)
50	184519	Shop Test New Sgl Phase Mtrs		-	(5)	(5)		-	(0)	(0)
51	184523	Wire Reclamation		57	-	57		3	-	3
52	184542	Misc Material		-	(1)	(1)		-	(0)	(0)
53	184620	Const Clearing Line Oper		(6,179)	(8,664)	(14,843)		(310)	(435)	(745)
54	184621	T&D Budget Preparation		184	(39)	145		9	(2)	7
55	184622	Maintain Construction Standard		183	(50)	133		9	(3)	7
56	184630	Construction Clearing Prod		1,588	(405)	1,184		80	(20)	59
57	184810	Continuing Property Records		853	(222)	631		43	(11)	32
58	184890	E E I Dues Cleared		(8,638)	(5,529)	(14,168)		(433)	(278)	(711)
59	184915	Small Tools		-	(467)	(467)		-	(23)	(23)
60		Total CA Materials Test Year End	-	(15,173)	(15,654)	(30,827)	-	(761)	(786)	(1,547)
61		Total Materials and Supplies	$ (49,016)	$ (1,662,723)	$ (2,885,011)	$ (4,596,750)	$ (2,695)	$ (86,898)	$ (144,978)	$ (234,571)

Test Year Ending June 30, 2018

Line No.	GL Account	Description	Reference	Total Company Ending Balance	Total Company Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Kansas Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	252100	Customer Advances (1)	Section 12 Customer Advances	$ (639,459)	$ (14,396)	$ (653,855)	$ (16,333)	$ -	$ (16,333)
2	252110	Customer Advances (1)	Section 12 Customer Advances	(2,697,018)	574,466	(2,122,552)	-	-	
3	235000	Customer Deposits (2)	Section 12 Customer Deposits	(14,294,447)	441,271	(13,853,176)	(431,012)	(5,984)	(436,996)
4		Total		$ (17,630,925)	$ 1,001,342	$ (16,629,583)	$ (447,345)	$ (5,984)	$ (453,328)

WP-3 Revenue Requirement

Footnotes:
(1) Customer Advances are Direct Assigned
(2) Customer Deposit Allocator 3.02%

			Total Company								Test Year Ending June 30, 2018	
											Total Company	Kansas
Line No.	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Customer Advances	**Line Ext 12-15**	$ (1,966,979)	**Line Ext 12-16**	$ (2,258,599)	**WP-8.1 Cust Advances**	$ (2,780,095)	**WP-8.1 Cust Advances**	$ (2,395,575)	**WP-8.1 Cust Advances**	$ (2,776,408)	$ (16,333)
2	Customer Deposits	**WP 8.1 Cust Dep support MFR**	(12,220,681)	**WP 8.1 Cust Dep support MFR**	(13,041,001)	**WP 8.1 Cust Dep support MFR**	(13,632,840)	**WP 8.1 Cust Dep support MFR**	(13,347,989)	**WP 8.1 Cust Dep**	(13,853,176)	(436,996)
3	Total		$ (14,187,660)		$ (15,299,600)		$ (16,412,935)		$ (15,743,563)		$ (16,629,584)	$ (453,328)
												WP-1 Revenue Requirement

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company Ending Balance	Total Company Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Kansas Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
	Accumulated Deferred Income Taxes							
1	Accumulated Deferred Tax Assets	**WP 6.4 Acc. Deferred Tax Liab**	$ 93,840,636	$ (80,048,605)	$ 13,792,031	$ 700,787	$ (91,861)	$ 608,927
2	Accumulated Deferred Tax Liabilities	**WP 6.4 Acc Deferred Tax Asset**	(340,073,811)	48,316,069	(291,757,742)	(15,009,223)	2,002,118	(13,007,105)
3	Total Accumulated Deferred Income Taxes		$ (246,233,175)	$ (31,732,536)	$ (277,965,711)	$ (14,308,436)	$ 1,910,258	$ (12,398,178)

Test Year Ending June 30, 2018

		Total Company						Kansas		
Line No.	Description	CWIP Adjustment	Non-Cash/Disallowance Adj	Net NOL Against Plant Adj	Disallowed Plant Adj	Exclude as Already Tax Effected Adj	Total Adjustments	CWIP Adjustment	TDC Adjustment	Total Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g) =SUM (b) through (f)	(h)	(i)	(j) = (h) + (i)
1	**Adjustment Number**	**ADJ-5**	**Section 12**	**Section 12**	**Section 12**	**Section 12**		**ADJ- 5**	**ADJ-17**	
2	Accumulated Deferred Tax Assets	$ 5,654	$ (72,815,370)	$ (5,370,220)	$ (1,231,254)	$ (637,414)	$ (80,048,605)	$ -	$ (91,861)	$ (91,861)
3	Accumulated Deferred Tax Liabilities	(18,471)	42,964,320	5,370,220	-	-	48,316,069	(622)	2,002,740	2,002,118
4	Total	$ (12,817)	$ (29,851,051)	$ (0)	$ (1,231,254)	$ (637,414)	$ (31,732,536)	$ (622)	$ 1,910,880	$ 1,910,258

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company: Ending Balance	Total Company: Pro Forma Adjustments	Total Company: Adjusted Ending Balance	Kansas: Ending Balance	Kansas: Pro Forma Adjustments	Kansas: Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Regulatory Assets	**WP-6.5 Reg Asset**	$ 205,635,975	$ (52,364,090)	$ 153,271,885	$ 4,392,625	$ (4,392,625)	$ -
2	Regulatory Liabilities	**WP-6.5 Reg Liab**	(328,945,867)	156,340,064	(172,605,803)	(8,510,504)	917,717	(7,592,787)
3	Total Regulatory Assets and Liabilities:		$ (123,309,892)	$ 103,975,974	$ (19,333,918)	$ (4,117,879)	$ (3,474,907)	$ (7,592,787)

Test Year Ending June 30, 2018

Line No.	Description	Kansas Revenue Requirement Amount	Average Daily Amount	Revenue Lag	Expense Lag	Net (Lead)/Lag Days	Cash Working Capital Requirement
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g) = (c) * (f)
1	Total Purchases Fuel and Power Expense	$ 5,885,048	$ 16,123	$ 43	$ (31)	$ 12	$ 197,834
2	Operation and Maintenance Expenses						
3	O&M, Labor	2,096,977	5,745	43	(12)	31	180,397
4	Pension Benefits (401K)	851,845	2,334	43	(12)	31	73,282
5	Post Retirement Benefits	124,560	341	43	(6)	38	12,879
6	Medical, Vision, and Dental Expenses	343,299	941	43	(16)	27	25,498
7	Life Insurance / AD&D	11,001	30	43	(16)	27	816
8	Affiliate Expenses	437,702	1,199	43	(35)	8	9,917
9	PSC Assessment	112,594	308	43	17	61	18,703
10	O&M, Other Non-Labor	5,044,504	13,821	43	(29)	14	196,114
11	Total O&M expenses (less depreciation):	9,022,481	24,719				517,606
12	Taxes Other Than Income Taxes						
13	Ad Valorem	971,003	2,660	43	(195)	(152)	(403,645)
14	Payroll Taxes	137,494	377	43	(11)	32	12,141
15	Total Taxes Other Than Income Taxes:	1,108,497	3,037				(391,504)
16	Federal Income Tax	625,083	1,713	43	(37)	6	10,960
17	State Income Tax	267,115	732	43	(37)	6	4,684
18	Annual Interest Requirements	1,449,491	3,971	43	(91)	(48)	(190,062)
19	Sales Tax and Use Tax	-	-	43	(29)	14	-
20	Total customer supplied funds:	2,341,689	6,416				(174,418)
21	Net cash working capital:	$ 18,357,715	$ 50,295				$ 149,519

		Test Year			
Line No.	**Description**	**Amount**	**% of Total**	**Cost Rate**	**Weighted Cost**
	(a)	(b)	(c)	(d)	(e) = (c) * (d)
1	First Mortgage Bonds/Unsecured Debt	$ 766,257,639	48.35%	4.70%	2.27%
2	Commercial Paper	-	0.00%	0.00%	0.00%
3	Total Debt Capital	766,257,639	48.35%	4.70%	2.27%
4	Trust Preferred Securities	-	0.00%	0.00%	0.00%
5	Common Equity	818,704,469	51.65%	10.20%	5.27%
6	Total	$ 1,584,962,108	100.00%		7.54%

		Pro-Forma Test Year			
Line No.	**Description**	**Amount**	**% of Total**	**Cost Rate**	**Weighted Cost**
	(a)	(b)	(c)	(d)	(e) = (c) * (d)
7	First Mortgage Bonds/Unsecured Debt	$ 766,257,639	48.35%	4.70%	2.27%
8	Commercial Paper	-	0.00%	0.00%	0.00%
9	Total Debt Capital	766,257,639	48.35%	4.70%	2.27%
10	Trust Preferred Securities	-	0.00%	0.00%	0.00%
11	Common Equity	818,704,469	51.65%	10.20%	5.27%
12	Total	$ 1,584,962,108	100.00%		7.54%

			Total Company	
			Prior Year	Test Year
Line No.	FERC	Description	As of June 30, 2017	As of June 30, 2018
	(a)	(b)	(c)	(d)
1		*First Mortgage Bonds/Unsecured Debt:*		
2	221400	6.375% Series due 2018	$ 90,000,000	$ -
3	221500	4.65% Series, due 6/1/2020.	100,000,000	100,000,000
4	224102	6.70% Sr. Notes, Series due 2033	62,000,000	62,000,000
5	224103	5.80% Sr. Notes, Series due 7-1-2035	40,000,000	40,000,000
6	221801	5.875% Series, due 2037	80,000,000	80,000,000
7	221803	5.20% Series, due 9-1-2040	50,000,000	50,000,000
8	221804	3.58% Series, due 4-2-2027	88,000,000	88,000,000
9	221805	3.73% Series, due 5-30-33	30,000,000	30,000,000
10	221806	4.32% Series, due 5-30-43	120,000,000	120,000,000
11	221807	4.27%, Series, due 12-1-2044	60,000,000	60,000,000
12	221808	3.59% FMB Series due 8-20-2030	60,000,000	60,000,000
13	223120	4.53% Note Payable to LUC, due 6-1-2033	-	90,000,000
14		Unamortized Bond Premium-Discount & Expense	(14,487,081)	(13,742,361)
15		Total First Mortgage Bonds/Unsecured Debt	765,512,919	766,257,639
16		*Commercial Paper*	-	-
17		*Company Obligated Mandatorily Redeemable*		
18		Trust Preferred Securities Of Subsidiary	-	-
19		Holding Solely Parent Debentures - 8 1/2%	-	-
20		Total Preferred Securities	-	-
21		*Common Stock Equity:*		
22		Common Stock	43,993,363	43,993,363
23		Capital In Excess Of Par Value	663,017,789	663,017,789
24		Installments Received On Common Stock	-	-
25		Accumulated Other Comprehensive Income (Loss) (Net)	-	-
26		Retained Earnings	84,154,355	111,693,317
27		Total Common Stock Equity	791,165,507	818,704,469
28		Total Capitalization	$ 1,556,678,426	$ 1,584,962,108
29		Capitalization Ratios:		
30		First Mortgage Bonds/Unsecured Debt	49.18%	48.35%
31		Commercial Paper	0.00%	0.00%
32		Trust Preferred Securities Of Sub	0.00%	0.00%
33		Common Stock Equity	50.82%	51.65%
34		Total	100.00%	100.00%

Line No.	Description	Account	Total Company: 6/30/2018 Amount Outstanding	Total Company: Annual Cost
	(a)	(b)	(c)	(d)
1	6.375% Series due 2018	221400	$ -	$ -
2	4.65% Series, due 6/1/2020.	221500	100,000,000	4,650,000
3	6.70% Sr. Notes, Series due 2033	224102	62,000,000	4,154,000
4	5.80% Sr. Notes, Series due 7-1-2035	224103	40,000,000	2,320,000
5	5.875% Series, due 2037	221801	80,000,000	4,700,000
6	5.20% Series, due 9-1-2040	221803	50,000,000	2,600,000
7	3.58% Series, due 4-2-2027	221804	88,000,000	3,150,400
8	3.73% Series, due 5-30-33	221805	30,000,000	1,119,000
9	4.32% Series, due 5-30-43	221806	120,000,000	5,184,000
10	4.27%, Series, due 12-1-2044	221807	60,000,000	2,562,000
11	3.59% FMB Series due 8-20-2030	221808	60,000,000	2,154,000
12	4.53% Note Payable to LUC, due 6-1-2033	223120	90,000,000	4,077,000
			780,000,000	36,670,400
13	Annual Cost Rate			4.70%
14	Commercial Paper		-	-
15	Annual Cost Rate		0.00%	0.00%
16	Trust Preferred Securities Of Subsidiary			
17	Holding Solely Parent Debentures - 8 1/2%		-	-
18	Premium And Expense		-	-
19	Total Company Obligated Mandatorily Redeemable		-	-
20	Annual Dividend Requirement Rate		0.00%	0.00%
21	Long-Term Debt and Trust Preferred Securities		$ 780,000,000	$ 36,670,400
22	Annual Cost Rate			4.70%

Line No	Description	Calendar Years			Prior Year	Test Year
		12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)
1	Gross Electric Operating Revenues	$ 553,029,845	$ 566,701,508	$ 582,711,334	$ 571,081,452	$ 631,294,945
2	Less Electric Operating Inc Exp Other Than Income Taxes	433,107,290	429,700,438	448,637,149	458,312,577	437,488,293
3	Balance	119,922,555	137,001,070	134,074,185	112,768,875	193,806,652
4	Water Net Revenue Before Income Taxes	2,055,327	2,064,979	2,055,080	2,059,175	2,075,897
5	Net Non-Operating Revenue Before Taxes	5,476,134	3,786,822	3,361,532	3,322,185	3,124,486
6	Net Nonelectric Income	7,531,461	5,851,801	5,416,612	5,381,360	5,200,383
7	Less Nonelectric Income In Excess Of 15% Of Net Earnings	-	-	-	-	-
8	Net Nonelectric Income Allowable	7,531,461	5,851,801	5,416,612	5,381,360	5,200,383
9	Total Revenue Available For Interest	127,454,016	142,852,871	139,490,797	118,150,235	199,007,035
10	Annual Interest Requirement	$ 40,130,900	$ 38,330,900	$ 38,330,900	$ 38,330,900	$ 36,670,400
11	Interest Coverage Ratio (Must Be 2 Or Greater)	3.18	3.73	3.64	3.08	5.43

Line No.	FERC	Description	Reference	Total Company: Calendar Year End 12/31/2015	Total Company: Calendar Year End 12/31/2016	Total Company: Calendar Year End 12/31/2017	Total Company: Test Year 6/30/2017	Total Company: Test Year 6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	301-398	Electric Plant In Service (Excluding ARO)	BS Elect. & Water	$ 2,454,791,583	$ 2,706,987,593	$ 2,781,264,036	$ 2,748,009,115	$ 2,827,514,758
2	101	Property Under Capital Lease		5,283,795	5,283,795	5,213,047	5,283,795	5,213,047
3	105	Electric Plant Held For Future Use		742,752	742,752	872,756	742,752	872,756
4		Electric Plant		2,460,818,130	2,713,014,141	2,787,349,839	2,754,035,663	2,833,600,560
5	810-898	MO Water		13,109,498	13,249,809	13,923,230	13,352,522	14,035,935
6		Water		13,109,498	13,249,809	13,923,230	13,352,522	14,035,935
7	107	Const. Work In Progress		182,584,782	28,484,444	31,763,912	28,122,060	39,945,966
8	118.2	CWIP - Water		75,364	340,300	101,560	452,209	32,820
9		Const. Work In Progress		182,660,145	28,824,744	31,865,472	28,574,269	39,978,786
10		Total Plant		2,656,587,774	2,755,088,694	2,833,138,541	2,795,962,454	2,887,615,281
11		Less Accumulated Depreciation (Exlc ARO):						
12	108/111	Electric		727,163,829	781,816,926	826,156,134	806,276,815	857,464,318
13		Net Plant		1,929,423,945	1,973,271,768	2,006,982,407	1,989,685,639	2,030,150,963
14		**Current Assets:**						
15	131	Cash		6,106,005	6,265,463	5,882,771	6,611,222	6,236,929
16	135	Working Funds		274,302	204,685	213,089	151,667	160,136
17	136	Temporary Cash Investments		100,000	-	-	-	-
18	142.1	Customer Accounts Receivable		38,858,565	42,554,197	46,056,260	43,027,574	57,357,838
19	142.2	Cust Accts Rec-Merch & Appl		-	-	-	-	-
20	144	Bad Debt Reserve - Electric		(350,000)	(330,000)	(350,000)	(406,618)	(425,647)
21	173	Unbilled Revenue Receivable		16,222,490	18,880,611	17,850,464	15,175,043	19,372,444
22	134	Harris Trust & Svgs Bk - Trustee		59,146	61,920	64,853	61,920	64,853
23	141	AR Refund Control		50	-	-	-	-
24	143	Other Accounts Receivable		27,622,231	3,593,008	9,990,868	7,513,997	6,520,412
25	144.4	Bad Debt Misc. Accounts Receivable		-	1	-	-	-
26	146	Accounts Receivable From Non-Utility Subsidiary		3,116,635	3,085,316	5,014,610	1,708,731	2,590,060
27	171	Int & Dividends Receivable		2,775	2,073	7,160	-	-
28	172	Rents Rec		41,053	47,053	49,848	45,887	68,588
29	154	Material		25,442,030	29,174,790	31,220,248	30,049,121	32,946,660
30	163	Stores		(69,059)	(66,939)	22,651	4,811	6,464
31	151	Fuel Stock		30,184,905	22,943,234	24,111,839	21,138,923	21,044,298
32	152	Fuel Stock Expense - Coal		-	-	3,603	-	-
33	175	Deriv Inst Asset-FAC Current		1,292,943	5,714,996	6,227,058	9,635,015	86,360
34	176	Deriv Instr Asset Hedge Cur		-	-	-	-	-
35	182	Fuel Cost Recovery		6,558,866	7,142,083	17,282,453	17,025,699	29,327,384
36	165	Prepayments		8,688,741	9,368,448	9,470,383	9,723,102	8,151,213

Line No.	FERC	Description	Reference	Total Company: Calendar Year End 12/31/2015	Calendar Year End 12/31/2016	Calendar Year End 12/31/2017	Test Year 6/30/2017	Test Year 6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
37	158	Emission Allowance Inventory		8,266	8,266	8,266	8,266	
38	190.99	Cur Def Inc Tx-Other Comp Inc		-	-	-	-	
39		**Total Current Assets**		164,159,945	148,649,204	173,126,425	161,474,361	183,507,993
40		**Deferred Charges:**						
41	182.3 -182.9	Other Regulatory Assets		188,260,271	191,274,912	167,009,628	184,678,753	154,849,913
42	186.9	Miscellaneous Deferred Debits		464,390	253,633	122,881	188,257	739,221
43	189	Unamort Loss		9,731,141	9,057,684	8,384,226	8,720,955	8,047,497
44	181	Unamortized Debt Expense		8,145,250	-	-	-	-
45	175.6	Derivative Inst Asset Hedge Noncurrent		-	683,780	53,000	52,840	
46	123	Investments		97,065,904	94,609,720	92,153,535	93,381,627	90,925,443
47	124	Other Investments		123,131	-	-	-	
48	183	Prelim. Survey & Invest. Chgs.		155,488	299,722	4,041,357	1,749,250	6,933,989
49	184	Clearing Accounts		288,703	374,958	52,349	533,926	294,552
50	186	Miscellaneous Deferred Debits		2,618,288	2,522,867	1,817,826	2,157,164	975,088
51	253.9	Lease Obligation		(60,585,880)	(58,129,695)	(55,673,511)	(56,901,603)	(54,445,419)
52		**Total Deferred Charges**		246,266,687	240,947,580	217,961,291	234,561,168	208,320,284
53		**Total Assets**		2,339,850,576	2,362,868,552	2,398,070,122	2,385,721,168	2,421,979,240
54		**Capitalization & Liabilities:**						
55	201	Common Stock and Common Stock Rights		43,820,726	44,177,535	43,993,363	43,993,363	43,993,363
56	143	Common Stock Sub Receivable		-	-	-	-	-
57	202	Common Stock Subscriptions		-	-	-	-	-
58	207	Premium On Capital Stock		677,675,642	688,487,579	684,085,854	684,085,854	684,085,854
59	211	Other Paid-In Capital		982,946	952,391	866,935	866,935	866,935
60	212	Installments Received On Common		742,615	447,950	-	-	-
61	214	Capital Stock Expense		(21,935,000)	(21,935,000)	(21,935,000)	(21,935,000)	(21,935,000)
62		Retained Earnings		82,516,012	93,824,470	91,603,726	84,154,355	111,693,317
63	219	Accum Other Comprehensive Income		-	-	-	-	-
64		**Total Common Stockholders' Equity**		783,802,940	805,954,925	798,614,878	791,165,507	818,704,469
65		**Long -Term Debt:**						
66	204	Trust Preferred Stock Issued		-	-	-	-	-
67	227	Oblig Under Cap Lease-Noncurrent		3,580,105	3,250,840	2,838,492	3,078,051	2,662,993
68	181	Unamortized Debt Issuance Costs		-	(7,467,104)	(6,852,803)	(7,170,034)	(7,016,561)
69	221	Bonds		678,000,000	678,000,000	678,000,000	678,000,000	588,000,000
70	224	Noncur Liab Vehicle Financing		-	-	-	-	-
71	226	Unamortized Discount On Long-Term Debt-Dr.		(347,737)	(310,621)	(273,504)	(292,062)	(255,786)
72	223	4.53% NotePay LUC due 6-1-2033						90,000,000
73	224	Notes Payable		102,000,000	102,000,000	102,000,000	102,000,000	102,000,000

				Total Company				
				Calendar Year End			Test Year	Test Year
Line No.	FERC	Description	Reference	12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
74	226	Unamortized Discount		(285,758)	(270,385)	(255,013)	(262,699)	(247,326)
75		**Total Long-Term Debt**		782,946,610	775,202,730	775,457,172	775,353,255	775,143,320
76		**Total Long-Term Debt Stockholders' Equity**		1,566,749,550	1,581,157,655	1,574,072,050	1,566,518,763	1,593,847,789
77		**Current Liabilities:**						
78	228	Accum Misc Op Prov-Energy Center		-	-	-	-	-
79	231.1	Notes Payable Prepaid Insurance		-	-	-	-	-
80	232	Accounts Payable		32,299,086	30,633,121	43,512,247	30,539,196	37,183,838
81	234	AP Cash due to EDG		11,111,864	13,987,592	23,479,677	21,032,254	29,970,494
82	238	Dividends Declared		-	-	-	-	-
83	241	Tax Collections Payable		686,322	672,130	722,837	840,721	1,008,892
84	242	Misc. Current And Accrued Liabilities		28,013,375	18,226,998	29,386,449	28,596,776	8,723,230
85	220	Interunit Account		(158,632)	(158,632)	(158,632)	(152,571)	(158,632)
86	231	Short Term Debt		25,000,000	24,750,000	5,575,000	15,750,000	6,250,000
87	235	Customer Deposits		12,691,454	13,448,144	13,943,945	13,644,201	14,358,161
88	237	Interest Accrued		7,044,876	6,900,481	6,921,023	6,029,827	5,279,760
89	236	Taxes Accrued		2,669,977	3,029,993	5,258,231	34,930,756	29,997,276
90	238	DividDividends Declared-Common-Liab		-	3,896,360	-	-	-
91	244.2	Deriv Inst Liab-FAC Current		4,189,910	1,126,180	1,397,320	1,131,450	562,140
92	245	Derivative Inst Liab Hedge Current		-	-	-	-	-
93	221	Current Maturities		25,000,000	-	-	-	-
94	224	Current Liab Vehicle Fin		-	-	-	-	-
95	229	Other Current Liabilities		322,979	220,182	160,218	168,784	160,218
96	230	Asset Retirement Obilg Current						5,262,704
97	243	Oblig Under Cap Lease-Current		307,475	328,020	369,090	348,885	375,346
98	254	Regulatory Liabilities - Current		8,468,342	14,505,802	4,491,320	12,721,202	3,321,682
99		**Total Current Liabilities**		157,647,029	131,566,371	135,058,725	165,581,482	142,295,109
100		**Noncurrent Liabilities & Deferred Credits:**						
101	254	Regulatory Liabilities		123,153,744	123,754,433	307,333,129	118,069,787	325,624,185
102	190	Accumulated Deferred Income Taxes		(84,318,830)	(93,537,674)	(100,358,336)	(106,531,838)	(93,840,636)
103	282	Liberalized Depreciation		361,801,264	404,251,255	296,377,723	411,942,702	283,305,257
104	283	Other Accumulated Deferred Tax		94,493,195	93,338,059	63,259,604	92,548,939	56,768,554
105	255	Unamortized Investment Tax Credit		18,486,677	18,077,079	17,734,175	17,943,202	17,735,343
106	244	Unrealized loss in fair value of deriv contracts		3,630,290	1,238,990	637,850	1,365,230	1,004,910
107	228.3	Pension & Other Postretirement Benefit Oblig		74,834,777	71,455,944	68,982,556	81,766,734	68,921,366
108	228.2	Accum Prov Inj & Damages		3,721,897	4,609,882	4,748,490	5,292,581	5,364,531
109	230	Asset Retirement Obligation		15,045,533	23,517,038	21,286,536	22,552,947	12,257,110
110	232	A/P To Empire District Trust		-	-	-	-	-

				Total Company				
				Calendar Year End			Test Year	Test Year
Line No.	**FERC**	**Description**	**Reference**	**12/31/2015**	**12/31/2016**	**12/31/2017**	**6/30/2017**	**6/30/2018**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
111	252	Customer Advances For Construction		2,097,872	2,389,492	2,910,988	2,526,468	3,467,371
112	253	Other		2,507,580	1,050,028	6,026,632	6,144,172	5,228,351
113		**Total Noncur Liabilities & Deferred Credits**		615,453,998	650,144,527	688,939,347	653,620,923	685,836,342
114		**Total Capitalization & Liabilities**	**BS Elect. & Water**	$ 2,339,850,576	$ 2,362,868,552	$ 2,398,070,122	$ 2,385,721,168	$ 2,421,979,240

Line No.	FERC	Description	Reference	Total Company — Calendar Years Ended 12/31/2015	12/31/2016	12/31/2017	Test Year 6/30/2017	Test Year 6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Comparative Statement of Income								
1	400	Operating Revenue	WP-8 Revenue	$ 553,029,845	$ 566,705,037	$ 582,711,334	$ 571,081,452	$ 631,294,945
2	401	Operation	WP-8 Operation Exp Details	275,793,337	270,122,505	286,840,576	296,124,170	271,118,227
3	402	Maintenance	WP-8 Maintenance Exp Details	47,149,133	45,111,281	46,433,155	46,338,360	49,555,788
4	403	Depreciation	Section 12	71,576,911	76,626,272	75,633,971	77,675,586	76,419,083
5	404	Amort. Of Electric Plant	Section 12	2,801,044	3,049,934	3,462,768	3,216,706	3,925,649
6	408	Taxes Other Than Income Taxes	Section 12	35,885,172	34,887,023	36,375,534	35,065,115	36,469,544
7	409	Income Taxes - Federal	Section 12	(2,986,853)	739,047	2,056,630	22,080,579	(6,015,766)
8	409	Income Taxes - State	Section 12	546,622	-	2,847,793	1,333,112	5,762,100
9	410	Provision For Deferred Income Taxes	Section 12	72,177,402	65,675,714	76,588,306	61,915,476	56,666,464
10	411	Inc. Taxes Def. In Prior Years	Section 12	(37,469,970)	(29,021,880)	(17,265,597)	(44,232,342)	7,873,586
11	411.4	Investment Tax Credit Adj. - Net	Section 12	(143,229)	(142,820)	(142,820)	(144,062)	(86,295)
12		Total Electric Operating Expenses		465,329,569	467,047,076	512,830,316	499,372,700	501,688,379
13		Net Electric Utility Operating Income		87,700,276	99,657,961	69,881,018	71,708,752	129,606,566
Comparative Statement of Retained Earnings:								
14		Retained Earnings:						
15		Balance Beginning Of Year	Balance Sheet Electric and Water	70,706,482	82,516,012	93,824,470	91,603,726	84,154,355
16		Transferred From Income	Inc Stmt Electric and Water	52,239,314	61,012,846	93,535,760	29,895,754	89,538,962
17		Dividends Declared Common Stock		40,429,784	49,704,387	95,756,504	37,345,124	62,000,000
18		Total Retained Earnings		82,516,012	93,824,470	91,603,726	84,154,355	111,693,317
			WP-8 Balance Sheet	$ 82,516,012	$ 93,824,470	$ 91,603,726	$ 84,154,355	$ 111,693,317

				Total Company					Kansas
				Three Preceding Calendar Years Ended			Test Year	Test Year	Test Year
Line No.	FERC	Description	Reference	12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	440	Residential	WP-8 Revenue Detail	$ 230,571,500	$ 236,618,843	$ 238,334,587	$ 235,294,419	$ 266,511,967	$ 12,431,473
2	442.1	Commercial	WP-8 Revenue Detail	171,727,135	172,219,226	175,235,495	169,950,039	185,854,262	6,176,544
3	442.2-6	Industrial	WP-8 Revenue Detail	88,185,220	86,238,172	88,720,987	85,517,177	93,999,760	5,278,289
4	444	Public Street and Highway Lighting	WP-8 Revenue Detail	4,178,397	4,115,107	4,173,789	4,144,972	4,257,545	261,544
5	445	Other Sales to Public Authorities	WP-8 Revenue Detail	11,094,471	11,144,497	11,254,224	11,121,510	11,793,735	481,944
6	448	Interdepartmental	WP-8 Revenue Detail	443,785	344,461	304,189	290,844	335,631	30,824
7		Total Margin Revenue		506,200,508	510,680,307	518,023,272	506,318,961	562,752,900	24,660,618
8	447.2, 3	On-System Wholesale	WP-8 Revenue Detail	18,031,526	19,723,905	19,110,853	19,683,975	20,120,325	-
9	447.1, 4, 5	Off-System Wholesale	WP-8 Revenue Detail	15,045,095	24,098,260	33,325,432	33,517,054	35,919,250	1,507,495
10	450-457	Other Revenues	WP-6 Sec 8C-1 Revenue Detail	13,752,716	12,202,564	12,251,776	11,561,463	12,502,471	(56,921)
11		Total Other Revenue		46,829,337	56,024,730	64,688,062	64,762,491	68,542,046	1,450,574
12		Total Revenues		$ 553,029,845	$ 566,705,037	$ 582,711,334	$ 571,081,452	$ 631,294,945	$ 26,111,192

				Total Company												Kansas			
				Three Preceding Calendar Years						Prior Test Year End		Test Year Ending June 30, 2018				Test Year Ending June 30, 2018			
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 6/30/2018 Balance	KS Allocation Factor	Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)	(q) = (o) * (p)	(r)	(s) = (q) + (r)
RESIDENTIAL																			
1	440	440010	Residential Sales-Arkansas	#	$ (5,589,389)	@	$ (4,901,110)	%	$ (4,922,968)	^	$ (4,863,658)	*	$ (5,432,221)	$ -	$ (5,432,221)	0.00% (1)	$ -	$ -	$ -
2	440	440011	Residential Sales-Ark-Unbilled		37,807		21,733		11,279		37,019		(78,427)	-	(78,427)	0.00% (1)	-	-	-
3	440	440020	Residential Sales-Kansas		(12,253,505)		(11,345,494)		(11,375,176)		(11,303,591)		(12,311,332)	-	(12,311,332)	100.00% (1)	(12,311,332)	-	(12,311,332)
4	440	440021	Residential Sales-Ks-Unbilled		127,189		(26,481)		26,338		181,412		(120,141)	-	(120,141)	100.00% (1)	(120,141)	-	(120,141)
5	440	440030	Residential Sales-Missouri		(209,554,330)		(216,874,371)		(220,058,756)		(222,801,214)		(237,353,638)	-	(237,353,638)	0.00% (1)	-	-	-
6	440	440031	Residential Sales-Mo-Unbilled		2,262,081		(1,774,943)		709,076		3,056,545		(2,653,585)	-	(2,653,585)	0.00% (1)	-	-	-
7	440	440034	Residential Sales-MO-FAC		(676,588)		3,199,740		1,940,857		5,130,556		(3,381,870)	-	(3,381,870)	0.00% (1)	-	-	-
8	440	440040	Residential Sales-Oklahoma		(5,055,618)		(4,863,333)		(4,672,561)		(4,768,603)		(5,143,759)	-	(5,143,759)	0.00% (1)	-	-	-
9	440	440041	Residential Sales-Ok-Unbilled		80,134		(14,229)		30,864		77,471		(33,631)	-	(33,631)	0.00% (1)	-	-	-
10	440	449102	Res Sales-MO- Refund		50,718		(40,355)		(23,540)		(40,355)		(3,363)	-	(3,363)	0.00% (1)	-	-	-
11			**Total Residential Revenues:**		(230,571,500)		(236,618,843)		(238,334,587)		(235,294,419)		(266,511,967)	-	(266,511,967)		(12,431,473)	-	(12,431,473)
COMMERCIAL																			
12	442	442110	Commercial Sales-Arkansas	#	(3,544,083)	@	(3,006,058)	%	(3,129,876)	^	(3,029,902)	*	(3,270,986)	-	(3,270,986)	0.00% (1)	-	-	-
13	442	442111	Commercial Sales-Ark-Unbilled		3,350		12,301		14,007		29,021		(36,173)	-	(36,173)	0.00% (1)	-	-	-
14	442	442120	Commercial Sales-Kansas		(6,272,292)		(5,806,912)		(5,932,709)		(5,831,911)		(6,144,314)	-	(6,144,314)	100.00% (1)	(6,144,314)	-	(6,144,314)
15	442	442121	Commercial Sales-Ks-Unbilled		57,737		801		(4,201)		94,642		(32,230)	-	(32,230)	100.00% (1)	(32,230)	-	(32,230)
16	442	442130	Commercial Sales-Missouri		(157,818,957)		(160,401,661)		(162,999,118)		(163,729,950)		(167,144,425)	-	(167,144,425)	0.00% (1)	-	-	-
17	442	442131	Commercial Sales-Mo-Unbilled		1,283,426		(840,258)		196,721		2,913,446		(1,140,152)	-	(1,140,152)	0.00% (1)	-	-	-
18	442	442134	Commercial Sales-MO-FAC		(497,105)		2,849,826		1,534,516		4,479,139		(2,902,787)	-	(2,902,787)	0.00% (1)	-	-	-
19	442	442140	Commercial Sales-Oklahoma		(5,089,553)		(4,976,869)		(4,918,615)		(4,900,475)		(5,167,507)	-	(5,167,507)	0.00% (1)	-	-	-
20	442	442141	Commercial Sales-Ok-Unbilled		110,234		(13,304)		25,417		63,042		(12,598)	-	(12,598)	0.00% (1)	-	-	-
21	449	449103	Comm Sales-MO- Refund		40,109		(37,092)		(21,637)		(37,092)		(3,091)	-	(3,091)	0.00% (1)	-	-	-
22			**Total Commercial Revenues:**		(171,727,135)		(172,219,226)		(175,235,495)		(169,950,039)		(185,854,262)	-	(185,854,262)		(6,176,544)	-	(6,176,544)
INDUSTRIAL																			
23	442	442213	Industrial Sales - Praxair-Mo	#	(3,918,407)	@	(4,113,442)	%	(4,185,189)	^	(4,132,346)	*	(4,188,014)	-	(4,188,014)	0.00% (1)	-	-	-
24	442	442215	Ind Sales Praxair-MO-FAC		(12,790)		144,290		58,455		200,681		(153,143)	-	(153,143)	0.00% (1)	-	-	-
25	442	442330	Oil Pipeline Pumping - Mo		(7,422,300)		(7,583,015)		(5,629,417)		(6,385,457)		(6,211,344)	-	(6,211,344)	0.00% (1)	-	-	-
26	442	442332	Oil Pipeline Pumping-MO-FAC		(7,631)		154,722		46,553		179,969		(152,867)	-	(152,867)	0.00% (1)	-	-	-
27	442	442340	Oil Pipeline Pumping - Ok		(812,905)		(697,708)		(752,254)		(696,564)		(837,786)	-	(837,786)	0.00% (1)	-	-	-
28	442	442510	Ot Indust Or Power Sales-Ark		(7,749,069)		(6,532,525)		(6,713,859)		(6,356,991)		(6,911,131)	-	(6,911,131)	0.00% (1)	-	-	-
29	442	442511	Ot Indust Sales-Ar-Unbilled		(8,611)		16,063		7,901		22,458		(15,886)	-	(15,886)	0.00% (1)	-	-	-
30	442	442520	Ot Indust Or Power Sales-Kan		(5,214,191)		(4,777,180)		(5,101,391)		(4,797,274)		(5,269,968)	-	(5,269,968)	100.00% (1)	(5,269,968)	-	(5,269,968)
31	442	442521	Ot Indust Sales-Ks-Unbilled		(263)		(1,892)		(424)		21,066		(8,321)	-	(8,321)	100.00% (1)	(8,321)	-	(8,321)
32	442	442530	Ot Indust Or Power Sales-Mo		(60,077,691)		(62,012,622)		(64,787,892)		(63,733,365)		(66,099,819)	-	(66,099,819)	0.00% (1)	-	-	-
33	442	442531	Ot Indust Sales-Mo-Unbilled		(14,202)		(34,998)		7,594		220,463		(69,924)	-	(69,924)	0.00% (1)	-	-	-
34	442	442533	Ot Indust or Pwr Sales-MO-FAC		(157,827)		1,517,327		643,586		2,188,300		(1,686,456)	-	(1,686,456)	0.00% (1)	-	-	-
35	442	442540	Ot Indust Or Power Sales-Okl		(2,832,717)		(2,291,727)		(2,307,070)		(2,237,882)		(2,396,890)	-	(2,396,890)	0.00% (1)	-	-	-
36	442	442541	Ot Indust Sales-Ok-Unbilled		19,949		(2,914)		5,575		12,316		3,667	-	3,667	0.00% (1)	-	-	-
37	449	449106	Ot Ind-Pwr Sales-MO- Refund		23,436		(22,551)		(13,155)		(22,551)		(1,879)	-	(1,879)	0.00% (1)	-	-	-
38			**Total Industrial Revenues:**		(88,185,220)		(86,238,172)		(88,720,987)		(85,517,177)		(93,999,760)	-	(93,999,760)		(5,278,289)	-	(5,278,289)
PUBLIC STREET & HWY LIGHTING																			
39	444	444010	Public Street & Hwy Light-Ar	#	(90,518)	@	(79,203)	%	(76,480)	^	(75,329)	*	(77,616)	-	(77,616)	0.00% (1)	-	-	-
40	444	444020	Public Street & Hwy Light-Ks		(260,162)		(254,506)		(257,446)		(251,390)		(261,544)	-	(261,544)	100.00% (1)	(261,544)	-	(261,544)
41	444	444030	Public Street & Hwy Light-Mo		(3,739,944)		(3,742,591)		(3,775,225)		(3,801,595)		(3,786,604)	-	(3,786,604)	0.00% (1)	-	-	-
42	444	444032	Public St & Hwy Light-MO-FAC		(4,060)		45,197		19,666		66,072		(45,025)	-	(45,025)	0.00% (1)	-	-	-
43	444	444040	Public Street & Hwy Light-Ok		(84,262)		(83,468)		(83,992)		(82,195)		(86,712)	-	(86,712)	0.00% (1)	-	-	-
44	449	449108	Pub St & Hwy Lt-MO- Refund		549		(536)		(312)		(536)		(45)	-	(45)	0.00% (1)	-	-	-
45			**Total Public Street & Hwy Lighting Revenues:**		(4,178,397)		(4,115,107)		(4,173,789)		(4,144,972)		(4,257,545)	-	(4,257,545)		(261,544)	-	(261,544)
OTHER PUBLIC AUTHORITIES																			
46	445	445010	Ot Sales To Pub Authorities-Ar	#	(471,002)	@	(411,838)	%	(403,460)	^	(384,822)	*	(437,994)	-	(437,994)	0.00% (1)	-	-	-
47	445	445020	Ot Sales To Pub Authorities-Ks		(537,697)		(490,272)		(468,065)		(472,336)		(481,944)	-	(481,944)	100.00% (1)	(481,944)	-	(481,944)
48	445	445030	Ot Sales To Pub Authorities-Mo		(9,820,252)		(10,197,330)		(10,281,729)		(10,339,314)		(10,468,856)	-	(10,468,856)	0.00% (1)	-	-	-
49	445	445032	Ot Sales to Public Auth-MO-FAC		(33,522)		182,333		113,157		294,139		(182,254)	-	(182,254)	0.00% (1)	-	-	-
50	445	445040	Ot Sales To Pub Authorities-Ok		(234,573)		(225,126)		(212,807)		(216,914)		(222,499)	-	(222,499)	0.00% (1)	-	-	-
51	449	449109	Ot Sales-PubAuth-MO- Refund		2,574		(2,264)		(1,320)		(2,264)		(189)	-	(189)	0.00% (1)	-	-	-
52			**Total Other Public Authorities Revenues:**		(11,094,471)		(11,144,497)		(11,254,224)		(11,121,510)		(11,793,735)	-	(11,793,735)		(481,944)	-	(481,944)
RESALE - MUNICIPALITIES																			
53	447	447221	Chetopa Ks On-Sys Municipalit	#	(729,787)	@	(691,504)	%	(722,929)	^	(692,422)	*	(823,058)	-	(823,058)	0.00% (1)	-	-	-
54	447	447231	Monett Mo On-Sys Municipalit		(12,612,039)		(13,843,292)		(13,443,490)		(13,858,995)		(14,119,856)	-	(14,119,856)	0.00% (1)	-	-	-
55	447	447232	Mt Vernon On-Sys Municipalit		(4,040,701)		(4,457,121)		(4,272,405)		(4,419,345)		(4,450,312)	-	(4,450,312)	0.00% (1)	-	-	-
56	447	447233	Lockwood On-Sys Municipalities		(649,000)		(731,989)		(672,030)		(713,213)		(727,100)	-	(727,100)	0.00% (1)	-	-	-
57			**Total Resale - Municipalities Revenues:**		(18,031,526)		(19,723,905)		(19,110,853)		(19,683,975)		(20,120,325)	-	(20,120,325)		-	-	-
INTERDEPARTMENTAL																			
58	448	448010	Interdepartmental Sales-Arkansas	#	(1,402)	@	(3,528)	%	-	^	-	*	-	-	-				
59	448	448020	Interdepartmental Sales-Kansas		(60,396)		(32,719)		(25,805)		(24,079)		(30,824)	-	(30,824)	100.00% (1)	(30,824)	-	(30,824)
60	448	448030	Interdepartmental Sales - Missouri		(380,368)		(313,886)		(281,277)		(274,496)		(299,472)	-	(299,472)	0.00% (1)	-	-	-
61	448	448032	Interdepartmental Sales-MO-FAC		(1,619)		5,672		2,893		7,731		(5,336)	-	(5,336)	0.00% (1)	-		
62			**Total Interdepartmental Revenues:**		(443,785)		(344,461)		(304,189)		(290,844)		(335,631)	-	(335,631)		(30,824)	-	(30,824)
OTHER																			
63	407	407301	Rate Ref 2017 Tax Reform AR	#		@	(3,528)	%		^		*	186,218	-	186,218	0.00% (1)	-	-	-

				Three Preceding Calendar Years						Prior Test Year End		Test Year Ending June 30, 2018				Test Year Ending June 30, 2018				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 6/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
64	407	407302	Rate Ref 2017 Tax Reform KS										590,715	-	590,715	100.00%	(1)	590,715	-	590,715
65	450	450020	Forfeited Discounts - Ks		(141,630)		(121,703)		(117,029)		(120,945)		(122,568)	-	(122,568)	100.00%	(1)	(122,568)	-	(122,568)
66	450	450030	Forfeited Discounts - Mo		(1,613,641)		(1,500,896)		(1,566,665)		(1,566,038)		(1,606,767)	-	(1,606,767)	0.00%	(1)	-	-	-
67	450	450040	Forfeited Discounts - Okla		(53,374)		(50,415)		(53,607)		(53,882)		(52,449)	-	(52,449)	0.00%	(1)	-	-	-
68	451	451031	Reconnect Charges-Arkansas		(3,131)		(2,767)		(2,784)		(2,509)		(2,492)	-	(2,492)	0.00%	(1)	-	-	-
69	451	451032	Reconnect Charges-Kansas		(5,515)		(5,430)		(4,925)		(5,030)		(4,880)	-	(4,880)	100.00%	(1)	(4,880)	-	(4,880)
70	451	451033	Reconnect Charges-Missouri		(115,420)		(92,945)		(96,940)		(93,370)		(101,170)	-	(101,170)	0.00%	(1)	-	-	-
71	451	451034	Reconnect Charges-Oklahoma		(4,381)		(3,205)		(3,006)		(3,381)		(2,995)	-	(2,995)	0.00%	(1)	-	-	-
72	451	451210	Other Misc Revenues - Arkansas										(3,451)	-	(3,451)	0.00%	(1)	-	-	-
73	451	451220	Other Misc Revenues - Kansas										(5,400)	-	(5,400)	100.00%	(1)	(5,400)	-	(5,400)
74	451	451230	Other Misc Revenues - Missouri		(3,012)		(2,328)		(1,968)		(2,328)		(120,453)	-	(120,453)	0.00%	(1)	-	-	-
75	451	451240	Other Misc Revenues - Oklahoma										(3,883)	-	(3,883)	0.00%	(1)	-	-	-
76	451	451420	KS Net Meter Application Fee		(100)		-		-		-					0.00%	(1)	-		
77	454	454010	Rent From Elec Property-Ark		(31,250)		(25,083)		(25,870)		(25,493)		(26,259)	-	(26,259)	0.00%	(1)	-	-	-
78	454	454020	Rent From Electric Property-Ks		(42,103)		(44,398)		(33,621)		(37,570)		(40,377)	-	(40,377)	100.00%	(1)	(40,377)	-	(40,377)
79	454	454030	Rent From Elec Property-Mo		(982,694)		(1,038,231)		(978,244)		(997,643)		(1,000,921)	-	(1,000,921)	0.00%	(1)	-	-	-
80	454	454040	Rent From Elec Property-Okla		(21,093)		(20,697)		(21,218)		(20,517)		(21,630)	-	(21,630)	0.00%	(1)	-	-	-
81	456	456010	Other Electric Revenue-Ark Sys		(18,024)		(16,213)		(16,554)		(16,032)		(17,291)	-	(17,291)	0.00%	(1)	-	-	-
82	456	456020	Other Electric Revenue-Ks Syst		(2,468)		(1,720)		(1,769)		(1,779)		(1,770)	-	(1,770)	100.00%	(1)	(1,770)	-	(1,770)
83	456	456030	Other Electric Revenue-Mo Syst		(301,963)		(296,752)		(314,897)		(308,208)		(323,991)	-	(323,991)	0.00%	(1)	-	-	-
84	456	456040	Other Electric Revenue-Ok Syst		(4,300)		(3,958)		(2,069)		(3,703)		(683)	-	(683)	0.00%	(1)	-	-	-
85	456	456075	REC Rev		(624,878)		(236,078)		(185,718)		(165,299)		(324,889)	-	(324,889)	4.73%	(2)	(15,374)	-	(15,374)
86	456	456081	Ot Elec Rev Off Sys Monett		(253,800)		(253,800)		(253,800)		(253,800)		(253,800)	-	(253,800)	0.00%	(1)	-	-	-
87	456	456082	Ot Elec Rev Off Sys Mt Vernon		(100,886)		(100,886)		(100,886)		(100,886)		(100,886)	-	(100,886)	0.00%	(1)	-	-	-
88	456	456083	Ot Elec Rev Off Sys Chetopa		(22,788)		(22,788)		(22,788)		(22,788)		(22,788)	-	(22,788)	0.00%	(1)	-	-	-
89	456	456084	Ot Elec Rev Off Sys Lockwood		(70,165)		(70,165)		(70,165)		(70,165)		(70,165)	-	(70,165)	0.00%	(1)	-	-	-
90	456	456091	PlumPt Transmission Credits-AR*		(1,113)		(1,143)		(946)		(1,045)		(938)	-	(938)	4.73%	(2)	(44)	-	(44)
91	456	456092	PlumPt Transmission Credits-KS*		(1,975)		(1,991)		(1,858)		(1,924)		(1,841)	-	(1,841)	4.73%	(2)	(87)	-	(87)
92	456	456093	PlumPt Transmission Credits-MO*		(33,066)		(33,222)		(33,565)		(33,393)		(33,579)	-	(33,579)	4.73%	(2)	(1,589)	-	(1,589)
93	456	456094	PlumPt Transmission Credits-OK*		(1,166)		(964)		(950)		(957)		(962)	-	(962)	4.73%	(2)	(46)	-	(46)
94	457	457131	Oth El Rev-Sched Sys Ctrl&Disp		(25,391)		(28,436)		(28,775)		(29,355)		(31,174)	-	(31,174)	0.00%	(1)	-	-	-
95	457	457132	Oth El Rev-React Supply&Volt		(49,908)		(66,116)		(81,222)		(78,784)		(84,150)	-	(84,150)	0.00%	(1)	-	-	-
96	457	457137	Ot El RvOffSys LTFSTF PTP Trns		(1,103,907)		(575,017)		(789,688)		(271,493)		(1,010,581)	-	(1,010,581)	4.73%	(2)	(47,820)	-	(47,820)
97	457	457138	Ot El RvOffSys NnFrm PTP Trns		(69,825)		4,484		(77,376)		(6,732)		(91,147)	-	(91,147)	4.73%	(2)	(4,313)	-	(4,313)
98	457	457140	Oth El Rev-Off-Sys Losses		(2,050)		-		-		-					0.00%		-		
99	457	457141	Sch 11 NITS		(5,771,666)		(5,358,770)		(4,743,994)		(5,002,816)		(4,956,605)	-	(4,956,605)	5.00%	(3)	(247,737)	-	(247,737)
100	457	457142	Sch 11 PTP		(594,674)		(462,496)		(677,371)		(439,039)		(676,230)	-	(676,230)	5.00%	(3)	(33,799)	-	(33,799)
101	457	457143	Sch 9 City of Monett		(1,016,286)		(1,095,496)		(1,227,405)		(1,140,476)		(1,292,633)	-	(1,292,633)	0.00%	(1)	-	-	-
102	457	457144	Sch 9 City of Mt Vernon		(360,314)		(367,171)		(407,647)		(380,497)		(424,116)	-	(424,116)	0.00%	(1)	-	-	-
103	457	457145	Oth El Rev-Off-Sys Dist		(21,331)		(21,331)		(21,331)		(21,331)		(21,331)	-	(21,331)	0.00%	(1)	-	-	-
104	457	457146	Sch 9 City of Lockwood		(59,798)		(61,841)		(70,299)		(64,854)		(70,973)	-	(70,973)	0.00%	(1)	-	-	-
105	457	457147	Sch 9 City of Chetopa		(74,790)		(69,316)		(61,930)		(64,793)		(65,142)	-	(65,142)	0.00%	(1)	-	-	-
106	457	457148	Sch 9 Kepco		(97,038)		(95,615)		(92,977)		(92,913)		(104,766)	-	(104,766)	0.00%	(1)	-	-	-
107	457	457149	Sch 11 NITS Monett		(5,482)		(6,500)		(8,187)		(7,366)		(8,189)	-	(8,189)	0.00%	(1)	-	-	-
108	457	457150	Sch 11 NITS Mt Vernon		(1,933)		(2,189)		(2,721)		(2,459)		(2,693)	-	(2,693)	0.00%	(1)	-	-	-
109	457	457151	Sch 11 NITS Lockwood		(321)		(368)		(468)		(419)		(453)	-	(453)	0.00%	(1)	-	-	-
110	457	457152	Oth El Rev-Off-Sys Transm		-		-		(5,406)		(5,406)		(414)	-	(414)	0.00%	(1)	-	-	-
111	457	457153	Sch 11 NITS Chetopa		(402)		(417)		(424)		(424)		(657)	-	(657)	0.00%	(1)	-	-	-
112	457	457154	Sch 11 NITS Kepco		(521)		(572)		(630)		(605)			-	-	0.00%	(1)	-	-	-
113	457	457160	Sch 1 PTP		(43,143)		(44,093)		(42,085)		(43,015)		(168,872)	-	(168,872)	4.73%	(2)	(7,991)	-	(7,991)
114			**Total Other Revenues:**		(13,752,716)		(12,202,564)		(12,251,776)		(11,561,463)		(12,502,471)	-	(12,502,471)			56,921	-	56,921
115			**Total On-System Electric Operating Revenues:**		(537,984,751)		(542,606,776)		(549,385,901)		(537,564,398)		(595,375,695)	-	(595,375,695)			(24,603,697)	-	(24,603,697)
For Resale - SPP IM																				
116	447	447850	SPP IM Rev	#	(15,009,198)	@	(24,055,355)	%	(33,291,325)	^	(33,481,354)	*	(35,883,565)	-	(35,883,565)	4.20%	(4)	(1,505,997)	-	(1,505,997)
117	447	447860	Bilateral/Off Line Aux Rev		(35,897)		(42,906)		(34,108)		(35,699)		(35,686)	-	(35,686)	4.20%	(4)	(1,498)	-	(1,498)
118			**Total For Resale - SPP IM Revenues:**		(15,045,095)		(24,098,260)		(33,325,432)		(33,517,054)		(35,919,250)	-	(35,919,250)			(1,507,495)	-	(1,507,495)
119			**Total Electric Operating Revenues:**		$ (553,029,845)		$ (566,705,037)		$ (582,711,334)		$ (571,081,452)		$ (631,294,945)	$ -	$ (631,294,945)			$ (26,111,192)	$ -	$ (26,111,192)

Footnotes:
(1) Direct assigned to jurisdiction
(2) Allocation WP-12-month average peak
(3) Allocation Other Revenue WP-12-month average peak
(4) Allocation WP-Expenses

Tickmarks:
= Traced and Agreed To 12/15 Trial Balance
@ = Traced and Agreed To 12/16 Trial Balance
% = Traced and Agreed To 12/17 Trial Balance
^ = Traced and Agreed To 6/30/17 Trial Balance
* = Traced and Agreed To 06/30/18 Trial Balance

			Total Company					Kansas
			Three Preceding Calendar Years			Prior Test Year End	Test Year	Test Year
Line No.	Description	Reference	12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Total Production Expenses	WP-8.3 Expense Detail	$ 212,238,438	$ 195,955,483	$ 178,815,164	$ 186,867,554	$ 206,647,698	$ 8,672,796
2	Total Transmission Expenses	WP-8.3 Expense Detail	23,667,303	22,089,277	25,025,575	23,655,320	25,075,914	1,224,251
3	Total Distribution Expenses	WP-8.3 Expense Detail	29,022,564	26,992,608	24,890,648	26,307,233	25,438,528	1,499,028
4	Total Customer Accounts Expenses	WP-8.3 Expense Detail	8,624,288	8,061,632	8,353,756	8,205,081	8,754,321	490,707
5	Total Customer Assistance Expenses	WP-8.3 Expense Detail	2,986,029	3,371,292	4,035,808	3,799,833	4,144,157	87,232
6	Total Sales Expenses	WP-8.3 Expense Detail	194,682	153,774	158,081	154,331	153,719	6,605
7	Total Administrative and General Expenses	WP-8.3 Expense Detail	1,414,137	1,213,932	1,340,377	1,245,552	1,321,445	103,350
8	Total Other Administrative and General Expenses	WP-8.3 Expense Detail	44,795,029	57,395,788	90,654,322	92,227,626	49,138,232	2,072,638
9	Total Operation and Maintenance Expenses		$ 322,942,470	$ 315,233,785	$ 333,273,730	$ 342,462,530	$ 320,674,014	$ 14,156,606

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
VARIABLE PRODUCTION EXPENSES																				
1			**Iatan/Plum Pt Deferred Operating Expenses:**																	
2	421	421022	MO Iat I Amrt O&M ER-2010-0130	#	$ 35,725	@	$ 35,691	%	$ 31,111	^	$ 33,372	*	$ 33,587	$ -	$ 33,587	0.00%	(1)	$ -	$ -	$ -
3	421	421025	KS PlumPt DfOM 10-EPDE-314-RTS		42,949		-		-		-		-		-					
4	421	421026	KS Iat II DfOM 10-EPDE-314-RTS		44,035		-		-		-		-		-					
5	421	421027	MO Iat II Amrt OM ER-2011-0004		77,583		78,925		57,796		67,158		67,584		67,584	0.00%	(1)	-		-
6	421	421029	MO PlmPt Amrt O&M ER-2011-0004		1,281		1,254		1,324		1,289		1,305		1,305	0.00%	(1)	-		-
7			**Total Iatan/Plum Pt Deferred Operating Expenses:**		201,573		115,870		90,231		101,819		102,476	-	102,476			-	-	-
8			**Fuel Expenses (Steam Generation):**																	
9	501	501001	Kansas Fuel Adj	#	822,575	@	(21,201)	%	(484,917)	^	184,793	*	(1,213,153)		(1,213,153)	100.00%	(1)	(1,213,153)		(1,213,153)
10	501	501002	MO Fuel Adj Current Period		6,868,941		7,860,621		(13,592,323)		(3,966,411)		(14,467,448)		(14,467,448)	0.00%	(1)	-		-
11	501	501003	MO Fuel Adj Recovery		1,391,142		(8,099,107)		(4,359,682)		(12,546,587)		8,509,737		8,509,737	0.00%	(1)	-		-
12	501	501004	Fuel Constr Acctg Iatan2 Def		(158,466)		(155,535)		(117,224)		(136,212)		(138,468)		(138,468)	0.00%	(1)	-		-
13	501	501005	Okla Fuel Cost Adj		(72,196)		58,560		63,024		44,478		61,195		61,195	0.00%	(1)	-		-
14	501	501011	Conv & Seminar-Fuel		1,938		995		-		995				-	0.00%	(1)	-		-
15	501	501042	Fuel - Coal		48,449,359		47,397,912		47,163,362		46,349,555		45,681,569		45,681,569	4.51%	(2)	2,059,402		2,059,402
16	501	501045	Fuel - Oil		1,016,917		556,518		751,700		539,542		1,020,499		1,020,499	4.51%	(2)	46,006		46,006
17	501	501054	Fuel - Natural Gas		2,332		-		-		-				-			-		-
18	501	501182	Ash Handling Expense		2,422		-		-		-				-			-		-
19	501	501183	Sales Of Ash		(75,017)		(66,123)		(75,980)		(71,906)		(66,454)		(66,454)	4.51%	(2)	(2,996)		(2,996)
20	501	501300	Fuel - Tires		75,406		63,019		53,205		45,060		50,977		50,977	4.51%	(2)	2,298		2,298
21	501	501400	Ops Labor-Fuel Handling		140,324		140,950		148,540		198,289		135,560		135,560	4.51%	(2)	6,111		6,111
22	501	501401	Ops Mtls-Fuel Handling		134,928		203,374		219,720		189,238		177,446		177,446	4.51%	(2)	8,000		8,000
23	501	501601	Fuel Administration - Asbury		101,349		86,498		49,571		72,342		40,191		40,191	4.51%	(2)	1,812		1,812
24	501	501604	Fuel Administration - Riverton		(47)		-		695		237		814		814	4.51%	(2)	37		37
25	501	501605	Fuel Administration Plum Point		141,636		117,224		104,209		109,696		105,503		105,503	4.51%	(2)	4,756		4,756
26	501	501910	Amrt SWPA Oz Beach-AR		(14,654)		(14,654)		(14,654)		(14,654)		(14,654)		(14,654)	0.00%	(1)	-		-
27	501	501920	Amrt SWPA Oz Beach-KS		(125,260)		(125,260)		(125,260)		(125,260)		(125,260)		(125,260)	100.00%	(1)	(125,260)		(125,260)
28	501	501930	Amrt SWPA Oz Beach-MO		(2,307,277)		(2,315,427)		(2,054,822)		(2,212,005)		(2,189,483)		(2,189,483)	0.00%	(1)	-		-
29	501	501940	Amrt SWPA Oz Beach-OK		(69,006)		(69,036)		(69,036)		(69,036)		(69,036)		(69,036)	0.00%	(1)	-		-
30			**Total Fuel Expenses (Steam Generation):**		56,327,345		45,619,328		27,660,128		28,592,153		37,499,534	-	37,499,534			787,013	-	787,013
31			**Steam Expenses:**																	
32	502	502084	Exp Of Coal Handling System	#	2,894	@	6,982	%	4,226	^	6,953	*	3,593		3,593	4.51%	(2)	162		162
33	502	502093	Exp Of Feedwater System		117,405		51,304		44,452		38,059		42,653		42,653	4.51%	(2)	1,923		1,923
34	502	502096	Exp To H2O Supply System		86,888		82,570		65,451		72,179		76,881		76,881	4.51%	(2)	3,466		3,466
35	502	502099	Exp Of Bottom & Fly Ash System		18,183		40,062		40,717		47,613		27,072		27,072	4.51%	(2)	1,220		1,220
36	502	502102	Exp Of Instrmnt & Meter Boiler		124,743		173,006		133,867		165,349		91,038		91,038	4.51%	(2)	4,104		4,104
37	502	502103	Expense of CEMS Equipment		-		-		5,938		-		32,237		32,237	4.51%	(2)	1,453		1,453
38	502	502105	Exp Of Draft Equipment		152		749		598		1,024		655		655	4.51%	(2)	30		30
39	502	502108	Exp Of Steam Boiler		1,128,428		1,046,457		867,840		1,086,744		412,138		412,138	4.51%	(2)	18,580		18,580
40	502	502109	Boiler Ops & Supervision		213,142		191,925		196,055		256,820		185,221		185,221	4.51%	(2)	8,350		8,350
41	502	502114	Steam Expenses - Other		2,136,262		1,659,267		1,375,888		1,534,833		1,359,000		1,359,000	4.51%	(2)	61,266		61,266
42	502	502168	Sel Catalytic Reduction - Ops		43		40		-		-		-		-	4.51%	(2)	-		-
43			**Total Steam Expenses:**		3,828,140		3,252,361		2,735,031		3,209,574		2,230,488	-	2,230,488			100,554	-	100,554
44			**Maintenance Supervision Expenses:**																	
45	510	510030	Mtce Supervision & Engineer	#	784,226	@	730,969	%	952,000	^	810,006	*	1,158,398		1,158,398	4.51%	(2)	52,223		52,223
46	510	510994	Iatan2 Mtc Rg Adj Amortization		(103,672)		415,385		(32,737)		450,989		(32,737)		(32,737)	0.00%	(1)	-		-
47	510	510995	IatCom Mtc Rg Adj Amortization		340,634		(418,129)		126,513		(500,666)		126,513		126,513	0.00%	(1)	-		-
48	510	510996	PP Mtc Trk Rg Adj Amortization		(39,244)		(182,880)		18,385		(120,299)		18,385		18,385	0.00%	(1)	-		-
49	510	510997	IatanII Mtc Rg Adj ER2011-0004		(54,191)		-		-		-		-		-	0.00%	(1)	-		-
50	510	510998	IatCom Mtc Reg Adj ER2011-0004		(41,265)		-		-		-		-		-	0.00%	(1)	-		-
51	510	510999	PP Mtc Trk Reg Adj ER2011-0004		(1,010,663)		-		-		-		-		-	0.00%	(1)	-		-
52			**Total Maintenance Supervision Expenses:**		(124,175)		545,345		1,064,161		640,030		1,270,559	-	1,270,559			52,223	-	52,223
53			**Maintenance of Boiler Plant Expenses:**																	
54	512	512138	Mtce Coalhandling	#	348,018	@	478,205	%	471,297	^	471,910	*	504,184		504,184	4.51%	(2)	22,729		22,729
55	512	512139	Mtce Of Rotary Dumper		121,748		95,692		109,769		106,980		64,377		64,377	4.51%	(2)	2,902		2,902
56	512	512141	Mtce Of Coal Sampler & Lab		1,321		2,470		4,287		6,575		183		183	4.51%	(2)	8		8
57	512	512144	Mtce Of C.E.M. Equipment		87,963		51,253		16,843		35,622		207		207	4.51%	(2)	9		9
58	512	512147	Mtce Of Coal Dozers		245,505		291,528		172,422		235,783		139,927		139,927	4.51%	(2)	6,308		6,308
59	512	512150	Mtce Of Feeders		14,045		52,336		34,804		50,421		65,122		65,122	4.51%	(2)	2,936		2,936
60	512	512153	Mtce Of Bottom & Fly Ash Syste		566,490		480,324		235,432		384,521		283,539		283,539	4.51%	(2)	12,782		12,782
61	512	512156	Mtce Instrmnt & Meters Boiler		85,426		63,987		50,798		46,214		59,702		59,702	4.51%	(2)	2,691		2,691
62	512	512159	Mtce Of Precipitator		24,406		3,133		-		-		-		-	4.51%	(2)	-		-
63	512	512160	Mtce Of Furnace		473,169		581,948		264,983		162,124		573,034		573,034	4.51%	(2)	25,833		25,833
64	512	512161	Mtce Of Cyclones		410,455		101,107		486,225		472,013		169,555		169,555	4.51%	(2)	7,644		7,644
65	512	512162	Mtce Of Draft Systems		138,286		240,691		278,175		235,280		178,540		178,540	4.51%	(2)	8,049		8,049
66	512	512163	Mtce Of Feedwater System Equip		164,861		148,176		70,837		129,323		374,992		374,992	4.51%	(2)	16,905		16,905
67	512	512164	Mtce Of Fuel Oil & Igniter Sys		3,222		28,132		23,587		38,988		16,242		16,242	4.51%	(2)	732		732

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
68	512	512165	Mtce Of Boiler Plant-Other		2,938,565		3,730,898		3,357,225		3,642,377		3,600,237		3,600,237	4.51%	(2)	162,305		162,305
69	512	512166	Mtce Of Burners		-		104		49,580		49,684				-	4.51%	(2)	-		-
70	512	512167	Mtce Of Boiler Drums & Headers		97,135		309,462		30,926		31,438		10,148		10,148	4.51%	(2)	458		458
71	512	512168	Sel Catalytic Reduction - Mtce		58,317		125,699		29,514		95,511		30,846		30,846	4.51%	(2)	1,391		1,391
72	512	512169	Mtce - Water Supply System		75,841		6,368		22,083		20,928		46,141		46,141	4.51%	(2)	2,080		2,080
73			**Total Maintenance of Boiler Plant Expenses:**		5,854,773		6,791,514		5,708,788		6,215,692		6,116,977	-	6,116,977			275,764	-	275,764
74			**Maintenance of Electric Plant Expenses:**																	
75	513	513122	Mtce Of Electrical Equipment	#	25,737	@	21,804	%	21,814	^	29,626	*	10,809		10,809	4.51%	(2)	487		487
76	513	513168	Mtce Of Turbine Plant		1,185,379		814,923		1,445,482		1,459,142		1,793,953		1,793,953	4.51%	(2)	80,874		80,874
77	513	513172	Mtce Of Turbine Inst. & Meters		2,335		4,429		12,844		9,281		28,970		28,970	4.51%	(2)	1,306		1,306
78	513	513173	Mtce Of Hydrogen System		37		483		-		293				-	4.51%	(2)	-		-
79	513	513174	Mtce Of Cooling Tower		135,576		118,768		69,400		76,501		85,782		85,782	4.51%	(2)	3,867		3,867
80	513	513175	Mtce Of Cooling Lake		-		100,238		56,530		109,063		86,152		86,152	4.51%	(2)	3,884		3,884
81	513	513178	Mtce Of Electrical Equipment		100,076		128,489		98,568		73,495		70,821		70,821	4.51%	(2)	3,193		3,193
82	513	513181	Mtce Of Condensing Equipment		12,376		21,150		29,402		9,714		36,839		36,839	4.51%	(2)	1,661		1,661
83	513	513182	Mtce Of Lube/Control Oil Equip		6,990		20,316		23,266		25,739		27,507		27,507	4.51%	(2)	1,240		1,240
84			**Total Maintenance of Electric Plant Expenses:**		1,468,505		1,230,600		1,757,306		1,792,853		2,140,833	-	2,140,833			96,512	-	96,512
85			**Fuel Expenses (Other Generation):**																	
86	547	547208	Comb Turb Fuel Sales - Nat Gas	#	-	@	(55,650)	%	-	^	(55,650)	*								
87	547	547210	Combust Turb Fuel Natural Gas		37,857,115		48,143,099		69,020,837		61,544,496		68,405,519		68,405,519	4.51%	(2)	3,083,836		3,083,836
88	547	547213	Fuel - No 2 Oil Fuel		711,644		30,618		264,144		211,378		2,968,727		2,968,727	4.51%	(2)	133,835		133,835
89	547	547300	MO/KS Deriv Unrecov Fuel Exp		(162,438)		(965,105)		423,001		(4,265)		(99,278)		(99,278)	5.18%	(3)	(5,146)		(5,146)
90	547	547301	NonFAS133 Deriv (Gain)/Loss		7,993,467		3,659,557		1,225,752		1,387,425		2,052,930		2,052,930	4.51%	(2)	92,550		92,550
91	547	547603	Fuel Adm Riverton Gas		-		-		812		-		812		812	4.51%	(2)	37		37
92	547	547605	Fuel Adm State Line		676		2,148		1,739		1,652		936		936	4.51%	(2)	42		42
93	547	547606	Fuel Adm Energy Center		790		2,148		1,333		1,652		530		530	4.51%	(2)	24		24
94	547	547607	Fuel Adm E Traders Commission		29,729		32,035		31,014		45,978		22,816		22,816	4.51%	(2)	1,029		1,029
95			**Total Fuel Expenses (Other Generation):**		46,430,984		50,848,849		70,968,633		63,132,665		73,352,992	-	73,352,992			3,306,206	-	3,306,206
96			**On-System Purchase Power (Energy):**																	
97	555	555430	Direct Purchases	#	35,816,609	@	38,029,305	%	38,719,099	^	38,645,504	*	50,027,144	(10,995,421)	39,031,723	4.51%	(2)	1,759,616		1,759,616
98	555	555700	TCR Unreal/Unrecov		108,489		53,127		(5,109,924)		188,702		-	-	-	4.51%	(2)	-		-
99	555	555800	DA Asset Energy Purchase		23,273,107		12,064,781		6,214,747		10,232,960		11,763,008	-	11,763,008	4.51%	(2)	530,296		530,296
100	555	555810	DA NonAsset Energy Purchase		399,853		-		-		-				-	4.51%	(2)	-		-
101	555	555820	DA Virtual Energy Purchase		1,374,411		639,295		852,157		942,585		3,027,547	-	3,027,547	4.51%	(2)	136,487		136,487
102	555	555840	DA Reg Up Cost		187,852		207,017		216,840		227,642		275,095	-	275,095	4.51%	(2)	12,402		12,402
103	555	555850	DA Reg Down Cost		180,493		74,337		75,685		81,099		88,715	-	88,715	4.51%	(2)	3,999		3,999
104	555	555860	DA Spin Reserve Cost		181,576		208,272		290,675		258,375		356,207	-	356,207	4.51%	(2)	16,058		16,058
105	555	555870	DA Supp Reserve Cost		118,760		85,644		82,207		80,910		81,894	-	81,894	4.51%	(2)	3,692		3,692
106	555	555880	DA Other PP Expense		(950,839)		654,903		739,710		678,719		224,906	-	224,906	4.51%	(2)	10,139		10,139
107	555	555900	RT Asset Energy Purchase		3,960,268		4,086,690		6,335,577		5,869,389		8,334,816	-	8,334,816	4.51%	(2)	375,748		375,748
108	555	555910	RT NonAsset Energy Purchase		11,840		5,179		-		184				-	4.51%	(2)	-		-
109	555	555920	RT Virtual Energy Purchase		403,585		508,868		558,527		566,704		712,187		712,187	4.51%	(2)	32,107		32,107
110	555	555940	RT Reg Up Cost		373,825		257,045		488,461		378,717		364,667		364,667	4.51%	(2)	16,440		16,440
111	555	555950	RT Reg Down Cost		315,443		344,650		923,057		617,705		700,612		700,612	4.51%	(2)	31,585		31,585
112	555	555960	RT Spin Reserve Cost		118,782		177,943		275,100		253,225		159,999		159,999	4.51%	(2)	7,213		7,213
113	555	555970	RT Supp Reserve Cost		8,795		3,451		6,500		6,384		5,073		5,073	4.51%	(2)	229		229
114	555	555980	RT Other PP Expense		(1,127,912)		(1,622,716)		(815,012)		(1,134,616)		(1,238,285)		(1,238,285)	4.51%	(2)	(55,824)		(55,824)
115	555	555990	TCR Settlements		869,791		(5,028,973)		(19,017,256)		(11,913,307)		(17,574,482)		(17,574,482)	4.51%	(2)	(792,287)		(792,287)
116	555	555995	Auction Revenue Rights		(7,120,808)		(3,296,926)		(5,942,504)		(4,551,952)		(9,428,198)		(9,428,198)	4.51%	(2)	(425,039)		(425,039)
117			**Total On-System Purchase Power (Energy):**		58,503,921		47,451,892		24,893,646		41,428,929		47,880,905	(10,995,421)	36,885,485			1,662,860	-	1,662,860
118			**Less: Off-System Fuel & Purchase Power (Energy):**		-		-		-		-		-	-	-			-	-	-
119			**Total Variable Production Expenses:**		**172,491,066**		**155,855,758**		**134,877,923**		**145,113,714**		**170,594,766**	**(10,995,421)**	**159,599,345**			**6,281,132**	**-**	**6,281,132**
FIXED PRODUCTION EXPENSE (STEAM)																				
120			**Operation Supervision and Engineering Expenses:**																	
121	500	500011	Conv & Seminar-Operations	#	14,795	@	2,937	%	48,093	^	10,739	*	77,124		77,124	4.73%	(4)	3,650		3,650
122	500	500035	Professional Assc Dues-Prod		367		1,835		1,235		865		371		371	4.73%	(4)	18		18
123	500	500036	Opr Spr & Eng-Air Abate&Monit		298,212		231,124		293,481		326,163		255,430		255,430	4.73%	(4)	12,087		12,087
124	500	500037	Op Supv-Water Monit & Compliance		-		-		683		1,541,572		11,574		11,574	4.73%	(4)	548		548
125	500	500038	Op Supv-Solid Wste Monit&Compl		-		-		150		4,076		150		150	4.73%	(4)	7		7
126	500	500039	Operation Supervision & Eng		1,601,577		1,515,200		1,642,789		5,621		1,704,088		1,704,088	4.73%	(4)	80,637		80,637
127	500	500046	Micro Software-Production		6,044		2,641		3,176		450,989		750		750	4.73%	(4)	35		35
128	500	500180	Regulatory & Environm Report		6,493		5,621		10,903		(500,666)		10,903		10,903	4.73%	(4)	516		516
129	500	500994	IatanII Op Rg Adj Amortization		(93,746)		415,385		(32,737)		(120,299)		(32,737)		(32,737)	0.00%	(1)	-		-
130	500	500995	IatCom Op Reg Adj Amortization		538,755		(418,129)		126,513		-		126,513		126,513	0.00%	(1)	-		-
131	500	500996	PP Op Trk Reg Adj Amortization		(37,146)		(182,880)		18,385		-		18,385		18,385	0.00%	(1)	-		-
132	500	500997	IatanII Opr Rg Adj ER2011-0004		46,844		-		-		-				-	0.00%	(1)	-		-
133	500	500998	IatCom Opr Reg Adj ER2011-0004		(133,085)		-		-		-				-	0.00%	(1)	-		-

				Total Company												Kansas			
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year			
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor	Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)	(q) = (o) * (p)	(r)	(s) = (q) + (r)
134	500	500999	PP Op Trk Reg Adj ER-2011-0004		748,135		-		-		-				-	0.00% (1)	-		-
135	500		**Total Operation Supervision and Engineering Expenses:**		2,997,246		1,573,733		2,112,671		1,719,059		2,172,551	-	2,172,551		97,497	-	97,497
136			**Electric Expenses:**																
137	505	505112	Exp-Condens & Cooling H2O Sys	#	153,814	@	232,623	%	413,368	^	228,753	*	586,242		586,242	4.73% (4)	27,741		27,741
138	505	505117	Exp Of Lube Oil System		3,756		7,609		1,909		3,920		14,614		14,614	4.73% (4)	692		692
139	505	505118	Expense of Generator		-		-		6,657		-		21,553		21,553	4.73% (4)	1,020		1,020
140	505	505119	Exp Of H2 System		7,395		-		-		-		-		-	4.73% (4)	-		-
141	505	505120	Exp Of Turbine Plant		462,499		144,559		306,697		126,568		483,521		483,521	4.73% (4)	22,880		22,880
142	505	505422	Electric Expense - Iatan		368,295		382,979		392,635		393,386		376,819		376,819	4.73% (4)	17,831		17,831
143	505	505426	Electric Ops & Supervision		161,988		163,723		168,226		228,253		156,084		156,084	4.73% (4)	7,386		7,386
144			**Total Electric Expenses:**		1,157,746		931,493		1,289,493		980,881		1,638,832	-	1,638,832		77,549	-	77,549
145			**Miscellaneous Steam Power Expenses:**																
146	506	506025	Safety Expenses-Prod	#	76,689	@	133,691	%	132,091	^	163,941	*	75,233		75,233	4.73% (4)	3,560		3,560
147	506	506126	Misc Steam Power Expenses		1,317,448		912,026		1,104,013		1,010,310		1,121,766		1,121,766	4.73% (4)	53,082		53,082
148	506	506128	Powdered Activated Carbon		-		8		-		8				-	4.73% (4)	-		-
149	506	506168	Exp of Catalytic Reducer - Opr		37,307		67,819		50,008		59,547		39,210		39,210	4.73% (4)	1,855		1,855
150	506	506173	Exp of Scrubber		7,492		6,781		15,587		1,580		15,587		15,587	4.73% (4)	738		738
151	506	506175	Exp of Baghouse		52,330		44,675		15,504		51,848		360		360	4.73% (4)	17		17
152	506	506176	Exp of Hydrator		120		1,810		1,953		3,763				-	4.73% (4)	-		-
153	506	506201	Limestone Expense		761,615		1,026,443		834,448		961,318		799,648		799,648	4.73% (4)	37,839		37,839
154	506	506202	Ammonia Expense		870,663		664,655		542,098		578,024		506,654		506,654	4.73% (4)	23,975		23,975
155	506	506203	Powdered Activated Carbon		135,356		170,024		134,751		173,133		113,821		113,821	4.73% (4)	5,386		5,386
156	506	506204	Lime Expense		254,255		224,270		211,047		223,482		259,559		259,559	4.73% (4)	12,282		12,282
157	506	506205	Ash and FGD By product Disposa		120,095		106,954		149,135		121,160		151,492		151,492	4.73% (4)	7,169		7,169
158	509	509052	Emission Allowance Exp		750		-		-		-		-		-	4.73% (4)	-		-
159			**Total Miscellaneous Steam Power Expenses:**		3,634,119		3,359,156		3,190,633		3,348,112		3,083,330	-	3,083,330		145,903	-	145,903
160			**Rents:**																
161	507	507129	Rents - Energy Supply	#	2,111	@	47,882	%	55,185	^	47,892	*	65,605		65,605	4.73% (4)	3,104		3,104
162			**Total Rents:**		2,111		47,882		55,185		47,892		65,605	-	65,605		3,104	-	3,104
163			**Maintenance of Structures Expenses:**																
164	511	511127	Mtce Of Structures	#	866,679	@	946,130	%	1,216,821	^	984,677	*	1,318,683		1,318,683	4.73% (4)	62,400		62,400
165	511	511132	Mtce Of Structures - Environ		10,709		1,838		8,503		4,559		6,659		6,659	4.73% (4)	315		315
166	511	511135	Mtce Of Structures - Other		450,070		321,496		298,240		283,556		268,062		268,062	4.73% (4)	12,685		12,685
167	511	511176	Mtce Of Wastewater Treatment		1,466		1,218								-	4.73% (4)	-		-
168			**Total Maintenance of Structures Expenses:**		1,328,923		1,270,682		1,523,564		1,272,792		1,593,404	-	1,593,404		75,400	-	75,400
169			**Maintenance of Miscellaneous Steam Plant Expenses:**																
170	514	514144	Mtce of C.E.M. Equipment	#	17,443	@	21,530	%	41,299	^	33,700	*	63,151		63,151	4.73% (4)	2,988		2,988
171	514	514158	Mtc Of Auxiliary Plant Equip		658,831		341,079		346,898		309,236		289,987		289,987	4.73% (4)	13,722		13,722
172	514	514168	Mtce of SCR Catalytic Reducer		107,982		79,438		187,413		91,012		263,808		263,808	4.73% (4)	12,483		12,483
173	514	514171	Mtce Of Misc Steam Plant		117,518		146,080		90,592		79,392		166,784		166,784	4.73% (4)	7,892		7,892
174	514	514173	Mtce of Scrubber		195,927		127,818		104,730		127,843		204,470		204,470	4.73% (4)	9,675		9,675
175	514	514174	Mtce of PAC System		-		-		-		-		159		159	4.73% (4)	8		8
176	514	514175	Mtce of Baghouse		200,647		595,793		194,793		544,485		68,183		68,183	4.73% (4)	3,226		3,226
177	514	514176	Mtce of Hydrator		5,515		36,543		62,204		65,061		45,091		45,091	4.73% (4)	2,134		2,134
178			**Total Maintenance of Miscellaneous Steam Plant Expenses:**		1,303,862		1,348,281		1,027,928		1,250,729		1,101,631	-	1,101,631		52,129	-	52,129
	FIXED PRODUCTION EXPENSES (HYDRO)																		
179			**Operation Supervision and Engineering Expenses:**																
180	535	535011	Conv & Seminar-Hydro	#	4,947	@	4,172	%	300	^	4,472	*	2,520		2,520	4.73% (4)	119		119
181	535	535301	Oper Supervision & Eng-Hydro		27,237		425		57,557		45,638		40,422		40,422	4.73% (4)	1,913		1,913
182			**Total Operation Supervision and Engineering Expenses:**		32,185		4,597		57,857		50,110		42,942	-	42,942		2,032	-	2,032
183			**Hydraulic Expenses:**																
184	537	537316	Other Expenses - Hydro	#	6,170	@	7,041	%	20,705	^	20,972	*	31,552		31,552	4.73% (4)	1,493		1,493
185			**Total Hydraulic Expenses:**		6,170		7,041		20,705		20,972		31,552	-	31,552		1,493	-	1,493
186			**Electric Expenses:**																
187	538	538325	Electric Expenses - Hydro	#	42,853	@	30,629	%	31,221	^	24,795	*	56,824		56,824	4.73% (4)	2,689		2,689
188			**Total Electric Expenses:**		42,853		30,629		31,221		24,795		56,824	-	56,824		2,689	-	2,689
189			**Miscellaneous Hydraulic Power Generation Expenses:**																
190	539	539025	Safety Expenses-Hydro	#	1,604	@	5,482	%	22,687	^	8,366	*	29,329		29,329	4.73% (4)	1,388		1,388
191	539	539332	Misc Hydro Generation Exp		355,292		194,878		202,278		197,879		234,170		234,170	4.73% (4)	11,081		11,081
192			**Total Miscellaneous Hydraulic Power Generation Expenses:**		356,895		200,360		224,965		206,244		263,499	-	263,499		12,469	-	12,469
193			**Maintenance Supervision and Engineering:**																
194	541	541304	Maint Supervision & Eng-Hydro	#	37,660	@	23,421	%	39,706	^	37,485	*	37,662		37,662	4.73% (4)	1,782		1,782
195			**Total Maintenance Supervision and Engineering:**		37,660		23,421		39,706		37,485		37,662	-	37,662		1,782	-	1,782

Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
196			**Maintenance of Structures Expenses:**																	
197	542	542307	House Expenses - Hydro	#	74,722	@	40,952	%	39,531	^	44,092	*	32,501		32,501	4.73%	(4)	1,538		1,538
198	542	542337	Maint Of Structures - Hydro		3,993		4,420		14,249		12,774		10,606		10,606	4.73%	(4)	502		502
199			**Total Maintenance of Structures Expenses:**		78,715		45,373		53,780		56,866		43,107	-	43,107			2,040	-	2,040
200			**Maintenance of Reservoirs, Dams, Water:**																	
201	543	543334	Maint Reservoirs Dam & Waterwy	#	132,814	@	143,659	%	162,615	^	160,840	*	139,241		139,241	4.73%	(4)	6,589		6,589
202			**Total Maintenance of Reservoirs, Dams, Water:**		132,814		143,659		162,615		160,840		139,241	-	139,241			6,589	-	6,589
203			**Maintenance of Electric Plant:**																	
204	544	544340	Maint Of Electric Plant- Hydro	#	34,708	@	37,294	%	38,438	^	36,985	*	40,844		40,844	4.73%	(4)	1,933		1,933
205			**Total Maintenance of Electric Plant:**		34,708		37,294		38,438		36,985		40,844	-	40,844			1,933	-	1,933
206			**Maintenance of Misc. Hydraulic Plant Expenses:**																	
207	545	545343	Maint-Hydro Plt Not Recreation	#	36,949	@	14,383	%	70,682	^	38,957	*	58,014		58,014	4.73%	(4)	2,745		2,745
208	545	545346	Maint-Misc Hydro Plt-Recreatn		89,686		168,102		38,808		108,562		27,497		27,497	4.73%	(4)	1,301		1,301
209			**Total Maintenance of Misc. Hydraulic Plant Expenses:**		126,635		182,484		109,491		147,519		85,511	-	85,511			4,046	-	4,046
FIXED PRODUCTION EXPENSES (OTHER)																				
210			**Operation Supervision and Engineering Expenses:**																	
211	546	546011	Conv & Seminars	#		@	4,305	%	2,509	^	1,922	*	2,167		2,167	4.73%	(4)	103		103
212	546	546204	Oper Super&Eng-Air Abate&Monit		22,030		30,241		53,276		45,638		66,638		66,638	4.73%	(4)	3,153		3,153
213	546	546205	Op Supv - Environmental		14,128		38,007		41,155		51,300		31,908		31,908	4.73%	(4)	1,510		1,510
214	546	546207	Oper Supervision & Eng		416,005		606,590		745,343		714,345		790,204		790,204	4.73%	(4)	37,392		37,392
215			**Total Operation Supervision and Engineering Expenses:**		452,163		679,143		842,283		813,205		890,918	-	890,918			42,158	-	42,158
216			**Generation Expenses:**																	
217	548	548123	Exp Of Prime Movers	#	1,205,502	@	2,100,376	%	2,684,266	^	2,479,618	*	2,890,853		2,890,853	4.73%	(4)	136,795		136,795
218	548	548124	Exp of Environmental Devices		128,813		125,447		191,198		180,953		157,826		157,826	4.73%	(4)	7,468		7,468
219	548	548125	Exp of Generators		29,308		33,411		36,428		41,723		36,424		36,424	4.73%	(4)	1,724		1,724
220	548	548126	Exp of Accessory Elec Equip		26,244		28,015		28,907		32,424		29,373		29,373	4.73%	(4)	1,390		1,390
221	548	548202	Ammonia Expense		169,783		205,132		199,494		209,041		246,547		246,547	4.73%	(4)	11,667		11,667
222	548	548216	Gener Exp - Water Injection Sys						11,876				12,135		12,135	4.73%	(4)	574		574
223	548	548219	Generation Expense - Other		387,666		512,041		468,880		483,591		441,960		441,960	4.73%	(4)	20,913		20,913
224			**Total Generation Expenses:**		1,947,317		3,004,422		3,621,047		3,427,349		3,815,118	-	3,815,118			180,531	-	180,531
225			**Misc. Other Power Generation Expenses:**																	
226	549	549025	Safety Expenses-Comb Turbine	#	7,516	@	108,845	%	43,201	^	102,285	*	68,351		68,351	4.73%	(4)	3,234		3,234
227	549	549046	Micro Software - Comb Turbine		393		4,387		483		4,387		483		483	4.73%	(4)	23		23
228	549	549120	Exp of Misc Other Power		453,645		896,566		1,311,887		1,239,938		1,199,030		1,199,030	4.73%	(4)	56,738		56,738
229	549	549169	Riverton OprTrk MO ER2016-0023		-		(159,167)		(351,102)		(334,234)		(360,638)		(360,638)	0.00%	(1)	-		-
230	549	549222	Misc Other Power Expense		155,277		173,566		172,715		164,955		160,835		160,835	4.73%	(4)	7,611		7,611
231			**Total Misc. Other Power Generation Expenses:**		616,830		1,024,197		1,177,183		1,177,332		1,068,061	-	1,068,061			67,606	-	67,606
232			**Maintenance Supervision and Engineering:**																	
233	551	551201	Maint Supervision & Engineer	#	436,301	@	586,271	%	781,280	^	700,153	*	799,898		799,898	4.73%	(4)	37,851		37,851
234			**Total Maintenance Supervision and Engineering:**		436,301		586,271		781,280		700,153		799,898	-	799,898			37,851	-	37,851
235			**Maintenance of Structures Expenses:**																	
236	552	552121	Exp of Structures	#	35,532	@	53,462	%	84,318	^	69,278	*	57,284		57,284	4.73%	(4)	2,711		2,711
237	552	552122	Exp of Structures Fuel		2,889		2,297		2,238		2,429		2,106		2,106	4.73%	(4)	100		100
238	552	552135	Mtce Of Structures - SL		59,040		99,103		162,518		101,825		237,725		237,725	4.73%	(4)	11,249		11,249
239	552	552136	Mtce of Structures Fires		9,979		34,732		15,340		41,627		28,102		28,102	4.73%	(4)	1,330		1,330
240	552	552137	Mtce of Structures Fuel		50,529		13,690		11,039		7,676		61,064		61,064	4.73%	(4)	2,890		2,890
241			**Total Maintenance of Structures Expenses:**		157,969		203,284		275,454		222,835		386,280	-	386,280			18,279	-	18,279
242			**Maintenance of Generating and Electric Expenses:**																	
243	553	553144	Mnt CEM Equip Combustion Turb	#	10,517	@	-	%	-	^	-	*								
244	553	553157	Mtce of Duct Burners		-		(467)		9,758		9,128		3,003		3,003	4.73%	(4)	142		142
245	553	553160	Mtce of Turbines		4,294,691		5,286,179		6,012,529		6,714,147		5,135,142		5,135,142	4.73%	(4)	242,994		242,994
246	553	553161	Mtce of Turbine Aux Equip		165,906		91,545		232,009		174,621		248,358		248,358	4.73%	(4)	11,752		11,752
247	553	553162	Mtce Of Hrsg Enclosure&Structr		39,361		107,201		12,056		105,700		18,913		18,913	4.73%	(4)	895		895
248	553	553163	Mtce Of Hrsg Pressure Parts		1,858,977		20,478		330,108		108,539		741,225		741,225	4.73%	(4)	35,075		35,075
249	553	553164	Mtce of Environmental Devices		80,157		108,654		159,650		139,942		141,527		141,527	4.73%	(4)	6,697		6,697
250	553	553165	Mtce of Cooling Systems		84,993		138,887		133,870		176,870		204,127		204,127	4.73%	(4)	9,659		9,659
251	553	553166	Mtce of Feedwater Systems		209,256		47,996		83,902		76,412		500,832		500,832	4.73%	(4)	23,699		23,699
252	553	553167	Mtce of Steam & Wtr Systems		10,203		7,170		139,185		23,438		(16,688)		(16,688)	4.73%	(4)	(790)		(790)
253	553	553168	Riverton Deferred Maintenance		2,720,248		3,528,307		5,505,654		4,973,552		5,467,337		5,467,337	4.73%	(4)	258,713		258,713
254	553	553169	Riverton MtcTrk MO ER2014-0351		-		(1,553,785)		(3,159,832)		(3,335,768)		(3,245,745)		(3,245,745)	0.00%	(1)	-		-
255	553	553170	Mtce of Generators		18,556		371,838		673,683		417,472		646,295		646,295	4.73%	(4)	30,583		30,583
256	553	553171	Mtce of Gen Excitation Sys		291		7,968		47,798		31,493		59,049		59,049	4.73%	(4)	2,794		2,794
257	553	553172	Mtce of Generator Aux Equip		1,450		399		14,689		9,451		10,358		10,358	4.73%	(4)	490		490

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
258	553	553173	Mtce of Station Transformers		381		1,249		42,818		2,640		43,777		43,777	4.73%	(4)	2,072		2,072
259	553	553174	Mtce of Accessory Elec Equip		94,933		120,628		63,642		72,506		131,972		131,972	4.73%	(4)	6,245		6,245
260	553	553175	Mtce of Elec Control System		48,964		31,312		202,051		120,950		179,930		179,930	4.73%	(4)	8,514		8,514
261	553	553181	Mtce of Condenser		-		11,462		18,182		8,669		27,456		27,456	4.73%	(4)	1,299		1,299
262	553	553182	Mtce of Auxiliary steam system		-		4,882		34,588		29,744		19,925		19,925	4.73%	(4)	943		943
263	553	553184	Mtce of Cooling Water Supply		-		21,346		18,610		32,731		263,723		263,723	4.73%	(4)	12,479		12,479
264	553	553228	Mtc Oth Gen&Elec Equip Wat Inj		35,474		32,554		39,564		40,829		44,121		44,121	4.73%	(4)	2,088		2,088
265	553	553231	Maint Of Gen & Elect Eq-Other		938,637		1,426,808		1,202,773		797,939		3,031,420		3,031,420	4.73%	(4)	143,446		143,446
266	553	553232	Unit #12 Combustion Turbine		678,539		56,635		(1,171)		4,502		3,309		3,309	4.73%	(4)	157		157
267	553	553260	Mtce of Turbines - Unit 10,11		-		30,824		148,797		126,395		120,804		120,804	4.73%	(4)	5,716		5,716
268			**Total Maintenance of Generating and Electric Expenses:**		11,291,534		9,900,071		11,964,912		10,861,899		13,780,169	-	13,780,169			805,663	-	805,663
269			**Maintenance of Misc. Other Power Expenses:**																	
270	554	554110	Exp of Misc Power Plant Equip	#	29,411	@	82,279	%	91,332	^	101,295	*	83,948		83,948	4.73%	(4)	3,972		3,972
271	554	554130	Mtce of Misc Plant Systems		227,263		229,450		311,935		308,621		246,951		246,951	4.73%	(4)	11,686		11,686
272	554	554131	Mtce Of Misc Plant Tools		64,368		99,055		74,960		97,466		87,193		87,193	4.73%	(4)	4,126		4,126
273	554	554234	Maint- Misc Oth Power Gen Plt		287,298		317,355		276,331		316,437		295,925		295,925	4.73%	(4)	14,003		14,003
274			**Total Maintenance of Misc. Other Power Expenses:**		608,341		728,139		754,557		823,819		714,017	-	714,017			33,787	-	33,787
275			**On-System Purchased Power (Demand)**																	
276	555	555430	Resource Capacity		8,597,729		10,509,544		10,735,303		10,448,074		10,995,421		10,995,421	4.73%	(4)	520,301		520,301
277			**Total On-System Purchased Power (Demand)**		8,597,729		10,509,544		10,735,303		10,448,074		10,995,421	-	10,995,421			520,301	-	520,301
278			**System Control and Load Dispatching Expenses:**																	
279	556	556001	Mgmt & Admin- Trans Operations	#	34,045	@	31,192	%	25,709	^	28,395	*	24,479		24,479	4.73%	(4)	1,158		1,158
280	556	556012	Sys Control/Load Disp Training		31,755		41,411		51,879		48,905		104,172		104,172	4.73%	(4)	4,929		4,929
281	556	556023	Building Operations-Sys Cntrl		52,421		78,038		88,743		84,829		83,079		83,079	4.73%	(4)	3,931		3,931
282	556	556025	Safety Exp		9,412		9,416		7,600		6,951		6,524		6,524	4.73%	(4)	309		309
283	556	556201	Janitorial Exp-System Ops		11,274		14,981		14,880		14,990		13,860		13,860	4.73%	(4)	656		656
284	556	556205	Utilities - System Operations		1,422		931		911		921		2,060		2,060	4.73%	(4)	97		97
285	556	556401	Sys Control & Generation Disp		394,726		378,514		388,691		388,521		375,634		375,634	4.73%	(4)	17,775		17,775
286	556	556410	EMS System Maintenance		185,053		204,816		210,419		211,453		226,645		226,645	4.73%	(4)	10,725		10,725
287	556	556411	Computer Operations		7,742		332		390		390		207		207	4.73%	(4)	10		10
288	556	556415	REC Fees & Commissions		51,633		65,642		19,696		35,924		22,575		22,575	4.73%	(4)	1,068		1,068
289	556	556412	Energy Trading		1,048,611		1,007,177		619,997		632,949		760,147		760,147	4.73%	(4)	35,970		35,970
290	556	556413	Energy Accounting		478,870		473,561		526,238		533,232		718,570		718,570	4.73%	(4)	34,003		34,003
291	556	556508	Telmetering/Load Control				532				11				-	4.73%	(4)	-		-
292	556	556523	Other Fiber Utility		1,379,352		1,379,352		1,379,352		1,379,352		1,379,352		1,379,352	4.73%	(4)	65,271		65,271
293			**Total System Control and Load Dispatching Expenses:**		3,686,316		3,685,894		3,334,504		3,366,822		3,717,304	-	3,717,304			175,902	-	175,902
294			**Other Expenses:**																	
295	557	557410	Pool Operation	#	381,126	@	282,583	%	297,734	^	289,739	*	306,254		306,254	4.73%	(4)	14,492		14,492
296	557	557448	Other Pwr Supply Expense		299,101		290,092		214,732		261,330		178,380		178,380	4.73%	(4)	8,441		8,441
297			**Total Other Expenses:**		680,227		572,675		512,466		551,069		484,635	-	484,635			22,933	-	22,933
298			**Less: Off-System Purchase Power (Demand):**		-		-		-		-		-	-	-			-	-	-
299			**Total Fixed Production Expenses:**		**39,747,371**		**40,099,725**		**43,937,241**		**41,753,839**		**47,048,353**	**-**	**47,048,353**			**2,391,664**	**-**	**2,391,664**
300			**Total Production Expenses:**		**212,238,438**		**195,955,483**		**178,815,164**		**186,867,554**		**217,643,118**	**(10,995,421)**	**206,647,698**			**8,672,796**	**-**	**8,672,796**
301			**Total Company Production Expenses Allocation:**																	
TRANSMISSION EXPENSES																				
302	560	560011	Conv & Seminar-Transm Op	#	106,536	@	106,007	%	94,512	^	81,894	*	95,930		95,930	4.73%	(4)	4,539		4,539
303	560	560025	Safety Expenses-Line Eng		1,021		410		528		274		770		770	4.73%	(4)	36		36
304	560	560046	Computer Software-Engineer		42,145		23,331		40,611		35,985		22,640		22,640	4.73%	(4)	1,071		1,071
305	560	560449	Transm Operation Super & Engr		-		311		-		295		54		54	4.73%	(4)	3		3
306	560	560490	Computer Programming		5		444		-		444				-	4.73%	(4)	-		-
307	560	560628	T & D Eng-Oper Supervision		97,983		117,586		105,701		101,666		95,551		95,551	4.73%	(4)	4,521		4,521
308	560	560629	Transmission System Planning		244,135		200,184		193,285		201,445		206,834		206,834	4.73%	(4)	9,787		9,787
309	561	561012	Load Dispatching Training		332		-		247		71		176		176	4.73%	(4)	8		8
310	561	561404	Transm System Operations		497,545		514,222		606,114		566,232		588,929		588,929	4.73%	(4)	27,868		27,868
311	561	561450	Transm Oper-Load Dispatching		1,482		1,427		1,301		1,239		1,196		1,196	4.73%	(4)	57		57
312	561	561501	NERC - Facilities Rating		502		-								-	4.73%	(4)	-		-
313	561	561505	Power Line Carrier Expenses		30,291		16,450		27,322		21,736		17,930		17,930	4.73%	(4)	848		848
314	562	562010	Transm Substation Operations		130,946		150,918		210,035		195,871		172,294		172,294	4.73%	(4)	8,153		8,153
315	562	562111	Exp of Substation & Switchyard		2,788		2,570		3,528		3,080		2,980		2,980	4.73%	(4)	141		141
316	562	562121	Substation Expenses		4,269		4,022		3,451		3,221		4,195		4,195	4.73%	(4)	198		198
317	562	562134	Mtce Of Substation Switchyard		238,183		270,765		279,305		276,815		303,925		303,925	4.73%	(4)	14,382		14,382
318	562	562452	Transmission Station Expenses				49				49				-	4.73%	(4)	-		-
319	563	563011	Overhead Trans Line Oper-161Kv		1,965		23,065		5,436		27,693		842		842	4.73%	(4)	40		40
320	563	563012	Overhead Trans Line Oper-69 Kv		93,747		48,959		34,650		45,666		28,360		28,360	4.73%	(4)	1,342		1,342

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
321	563	563014	Overhead Trans Ln Oper-34.5 Kv		2,608		2,043		2,632		1,166		8,012		8,012	4.73%	(4)	379		379
322	563	563015	Overhead Trans Line Oper-Other		2,187		2,839		4,657		1,359		4,418		4,418	4.73%	(4)	209		209
323	565	565413	Trans Of Electricity By Others		1,292		-				-				-	4.73%	(4)	-		-
324	565	565414	SPP Fixed Chg - Native Load		12,871,634		13,809,874		14,640,246		14,784,208		15,254,484		15,254,484	5.00%	(5)	762,436		762,436
325	565	565415	SPP Var Chg - Native Load		377,579		337,779		314,070		330,563		364,041		364,041	4.73%	(4)	17,226		17,226
326	565	565416	Non SPP Fixed Chg -Native Load		4,470,037		2,465,047		3,936,506		2,479,720		4,125,213		4,125,213	4.73%	(4)	195,204		195,204
327	566	566419	Off Sys Sales Trans Costs		136										-	4.73%	(4)	-		-
328	566	566450	RTO/ISO Development		261,812		229,469		152,528		206,991		43,657		43,657	4.73%	(4)	2,066		2,066
329	566	566458	Misc Transmission Expenses		22		967		123				68		68	4.73%	(4)	3		3
330	566	566459	NERC Compliance/CIPS (706)		240,977		132,812		104,539		126,102		40,680		40,680	4.73%	(4)	1,925		1,925
331	566	566462	NERC Compliance/EOP (693)		81,794		90,088		87,080		91,081		37,325		37,325	4.73%	(4)	1,766		1,766
332	567	567007	Rents - Transmission		175		175		175		175		175		175	4.73%	(4)	8		8
333	568	568631	T & D Eng-Maint Supervision		217,844		213,374		132,282		188,813		117,706		117,706	4.73%	(4)	5,570		5,570
334	569	569037	Trans Substa Structure Maint		9,762		5,892		8,567		1,761		9,330		9,330	4.73%	(4)	441		441
335	569	569203	General Maint-System Ops		7,656		1,691		7,689		4,141		5,770		5,770	4.73%	(4)	273		273
336	570	570040	Trans Substa Equip Maintenance		575,386		430,784		422,019		471,345		432,160		432,160	4.73%	(4)	20,450		20,450
337	570	570043	Trans Sub Breaker Routine Mtce		-		128,357		120,260		193,850		60,422		60,422	4.73%	(4)	2,859		2,859
338	570	570044	TransSub Trnsfrmr Routine Mtce		-		4,329		144,275		139,041		58,309		58,309	4.73%	(4)	2,759		2,759
339	570	570060	Trans Substation Inspections		64,775		76,333		69,416		68,392		83,895		83,895	4.73%	(4)	3,970		3,970
340	570	570177	Substation Maintenance - Plant		75,326		68,536		39,189		100,292		6,271		6,271	4.73%	(4)	297		297
341	570	570472	Transmission-Relays & Misc Eq		290,600		315,024		368,468		339,712		362,165		362,165	4.73%	(4)	17,138		17,138
342	570	570475	Generation - Relays & Misc Eq		28,067		40,968		36,879		42,389		39,913		39,913	4.73%	(4)	1,889		1,889
343	570	570511	Protection Relaying Channel Eq		2,130		8,521		6,419		7,858		10,519		10,519	4.73%	(4)	498		498
344	570	570517	Scada		248,593		280,650		359,932		309,257		339,044		339,044	4.73%	(4)	16,043		16,043
345	571	571001	OH Trans Tree Trimming Superv		146,005		197,277		170,602		246,623		157,378		157,378	4.73%	(4)	7,447		7,447
346	571	571041	Oh Trans Line Maint-161Kv		17,986		30,188		(15,242)		(3,500)		11,608		11,608	4.73%	(4)	549		549
347	571	571042	Overhead Trans Line Maint-69Kv		101,422		51,022		30,298		45,010		31,965		31,965	4.73%	(4)	1,513		1,513
348	571	571043	Oh Trans Line Maint-345 Kv		1,256		28,373		90,759		107,982		5,750		5,750	4.73%	(4)	272		272
349	571	571044	Oh Trans Line Maint-34.5Kv		6,410		5,056		465		274		1,640		1,640	4.73%	(4)	78		78
350	571	571045	Oh Trans Line Maint-Other		5,634		27,146		10,569		23,526		11,901		11,901	4.73%	(4)	563		563
351	571	571046	Oh Trans Line Tree Trim-345 Kv		-		-		49,911		46,364		3,547		3,547	4.73%	(4)	168		168
352	571	571047	Oh Trans Line Tree Trim-161Kv		14,851		11,396		28,385		38,343		1,733		1,733	4.73%	(4)	82		82
353	571	571048	Oh Trans Line Tree Trim-69 Kv		57,612		60,453		110,882		122,135		87,375		87,375	4.73%	(4)	4,135		4,135
354	571	571050	Oh Trans Ln Tree Trim-34.5 Kv		-		-		5,250		3,377		1,873		1,873	4.73%	(4)	89		89
355	571	571051	Oh Trans Line Tree Trim-Other		240		-								-	4.73%	(4)	-		-
356	571	571062	Trans OH reliab - labor&other		15,977		16,980		19,306		18,906		20,391		20,391	4.73%	(4)	965		965
357	571	571146	Chemical Tree Trim 345Kv		39,388				52,572		50,131		2,441		2,441	4.73%	(4)	115		115
358	571	571147	Chemical Tree Trim 161Kv		162,820		281,350		812,589		435,203		745,645		745,645	4.73%	(4)	35,284		35,284
359	571	571148	Chemical Tree Trim 69Kv	#	328,936	@	272,726	%	326,494	^	119,141	*	529,611		529,611	4.73%	(4)	25,061		25,061
360	571	571150	Chemical Tree Trim 34.5Kv		-		11,712				11,712		15,193		15,193	4.73%	(4)	719		719
361	571	571246	Side Trimming 345Kv		-		1,418				1,418				-	4.73%	(4)	-		-
362	571	571247	Side Trimming 161Kv		90,470		12,844				2,796				-	4.73%	(4)	-		-
363	571	571248	Side Trimming 69Kv		109,987		111,795		28,981		60,809		8,766		8,766	4.73%	(4)	415		415
364	571	571250	Side Trimming 34.5Kv				1,418		5,147		6,565				-	4.73%	(4)	-		-
365	571	571346	Transm Tree Trimming 345Kv		885		594								-	4.73%	(4)	-		-
366	571	571347	Transm Tree Trimming 161Kv		15,541		4,531		2,080		1,739		168		168	4.73%	(4)	8		8
367	571	571348	Trans Tree Trimming 69Kv		90,128		5,761		765		6,449				-	4.73%	(4)	-		-
368	571	571350	Transm Tree Trimming 34.5Kv		6,837		1,981		520		2,501				-	4.73%	(4)	-		-
369	571	571447	Hydro-Ax Tree Trim 161Kv		65,204		3,422						14,490		14,490	4.73%	(4)	686		686
370	571	571448	Hydro-Ax Tree Trim 69Kv		5,848		98,542		51,333		136,922		76,655		76,655	4.73%	(4)	3,627		3,627
371	571	571450	Hydro-Ax Tree Trim 34.5Kv		-		-		250		250				-	4.73%	(4)	-		-
372	571	571546	Tree Grinder-Tree Trim 345kv		-		1,534				1,534				-	4.73%	(4)	-		-
373	571	571547	Tree Grinder-Tree Trim 161kv		5,213		4,458		13,468		13,468		1,092		1,092	4.73%	(4)	52		52
374	571	571548	Tree Grinder-Tree Trim69kv		89,791		64,316		73,776		89,065		52,847		52,847	4.73%	(4)	2,501		2,501
375	571	571646	Dozer-Tree Trim 345kv		-		-						9,419		9,419	4.73%	(4)	446		446
376	571	571647	Dozer-Tree Trim 161kv		23,354		3,805		577		1,554		3,406		3,406	4.73%	(4)	161		161
377	571	571648	Dozer-Tree Trim 69kv		2,976		-		172,430		149,260		23,827		23,827	4.73%	(4)	1,128		1,128
378	571	571652	Trans 69Kv Pole Inspctn&Trmnt		-		-		35,000				37,512		37,512	4.73%	(4)	1,775		1,775
379	571	571656	Trans 345Kv Pole Insptn&Trmnt		-		-		60,183				60,183		60,183	4.73%	(4)	2,848		2,848
380	571	571658	Trans 34.5Kv Pole Insptn&Trmnt		-		225		426		2,672		(1,523)		(1,523)	4.73%	(4)	(72)		(72)
381	571	571740	TGR Tree Trimming-Transmission		-		-		4,747		4,747		19,459		19,459	4.73%	(4)	921		921
382	571	571910	Transm Maint 161KV Reliability		61,555		205,653		38,081		139,366		25,757		25,757	4.73%	(4)	1,219		1,219
383	571	571911	Transm Maint 69KV Reliability		319,552		242,920		(64,495)		97,790		23,585		23,585	4.73%	(4)	1,116		1,116
384	571	571912	Transm Maint 345KV Reliability		1,504		29,008		2,134		29,205		1,778		1,778	4.73%	(4)	84		84
385	571	571913	Trans Maint 34.5KV Reliability		7,285		5,781		659		1,094		263		263	4.73%	(4)	12		12
386	571	571920	Transm 69KV Pole Inspec Reliab		133,727		136,718		280,715		198,701		82,015		82,015	4.73%	(4)	3,881		3,881
387	571	571921	Transm 161KV Pole Inspc Reliab		16,358		-								-	4.73%	(4)	-		-
388	571	571998	Trans Reliab Reg Adj Amort		199,008		115,814		61,980		73,502		61,980		61,980	0.00%	(1)	-		-
389	571	571999	Trans Reliability Reg Adj		199,278		(83,209)				(83,209)				-	0.00%	(1)	-		-
390			**Total Transmission Expenses:**		23,667,303		22,089,277		25,025,575		23,655,320		25,075,914	-	25,075,914			1,224,251	-	1,224,251
	DISTRIBUTION EXPENSES																			
391	580	580001	Supervision Distribution Oper	#	486,164	@	599,981	%	830,094	^	714,416	*	820,465		820,465	5.50%	(6)	45,118		45,118

Line No.	FERC	GL Account	Description	Total Company: Calendar Years Ended: Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Prior Test Year End: Reference	6/30/2017	Test Year: Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	Kansas Test Year: KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
392	580	580002	System Perform Mgmt & Admin		63,779		61,031		9,506		35,419		6,782		6,782	5.50%	(6)	373		373
393	580	580011	Conv & Seminar-Distrib Op		63,142		65,122		48,540		56,185		52,905		52,905	5.50%	(6)	2,909		2,909
394	580	580016	Engineering Recruiting Exp		2,569		2,203		13,017		9,707		4,973		4,973	5.50%	(6)	273		273
395	580	580046	Software - Transf Superviser		-		117		460		460		1,000		1,000	5.50%	(6)	55		55
396	580	580627	Line Eng - Distrib Operations		167,539		170,307		169,214		168,715		185,844		185,844	5.50%	(6)	10,220		10,220
397	580	580628	Distribution System Planning		135,320		123,475		93,023		109,325		87,073		87,073	5.50%	(6)	4,788		4,788
398	580	580686	Maintain Construction Standard		69,492		68,669		53,998		75,920		49,484		49,484	5.50%	(6)	2,721		2,721
399	580	580690	AVL Mobile Operations		48,587		58,228		44,077		46,860		36,915		36,915	5.50%	(6)	2,030		2,030
400	582	582016	Distribution Substa Operations		209,364		226,590		203,644		228,066		207,549		207,549	5.50%	(6)	11,413		11,413
401	583	583019	Oh Distribution Line Oper		1,594,255		1,538,909		1,059,188		1,417,785		1,077,843		1,077,843	5.50%	(6)	59,271		59,271
402	583	583020	Truck Down Time - Line Oper		65,821		106,724		122,892		98,280		118,680		118,680	5.50%	(6)	6,526		6,526
403	583	583021	Truck Traveling Time - Line Op		22,494		29,827		2,218		15,735		3,896		3,896	5.50%	(6)	214		214
404	583	583025	Safety Exp-Oh Distrib Lines		29,253		16,997		18,208		15,955		26,397		26,397	5.50%	(6)	1,452		1,452
405	583	583172	Electric Testing-Oh Dis Lines		79,118		72,774		75,872		85,897		63,506		63,506	5.50%	(6)	3,492		3,492
406	583	583500	Training Dist Operations-Ovhd		55,450		34,108		21,151		34,458		14,736		14,736	5.50%	(6)	810		810
407	583	583501	Distr OH Training Stipend		3,192		604		1,677		297		2,315		2,315	5.50%	(6)	127		127
408	584	584022	Underground Distrib Line Oper		503,355		822,805		543,175		719,372		320,856		320,856	5.50%	(6)	17,644		17,644
409	584	584025	URG Dist Line Locates		287,521		48,893		372,222		145,299		517,998		517,998	5.50%	(6)	28,485		28,485
410	585	585025	Street Lightg & Signal Sys Exp		70,285		81,555		43,759		70,799		41,661		41,661	5.50%	(6)	2,291		2,291
411	586	586025	Safety Expenses-Meters		5,909		1,946		2,399		1,671		5,265		5,265	5.50%	(6)	290		290
412	586	586028	Meter Expense		1,776,125		1,678,366		1,395,889		1,547,516		1,297,834		1,297,834	5.50%	(6)	71,369		71,369
413	586	586029	Disconnects & Reconnects		742,760		830,245		1,165,143		982,746		1,193,932		1,193,932	5.50%	(6)	65,655		65,655
414	586	586120	Field Testing - Old		428,338		335,319		263,067		303,953		262,605		262,605	5.50%	(6)	14,441		14,441
415	586	586135	Load Research-Meters		56,721		71,456		161,412		79,026		183,681		183,681	5.50%	(6)	10,101		10,101
416	586	586140	Power Quality Investiagtions		25,545		18,004		19,989		21,867		13,203		13,203	5.50%	(6)	726		726
417	586	586150	AMR Fixed Network - Meters		191		1,629		71		1,637		52		52	5.50%	(6)	3		3
418	586	586155	AMR Radio - Meters		72,741		63,973		39,621		51,882		31,518		31,518	5.50%	(6)	1,733		1,733
419	587	587031	Service Call Expense		62,076		59,760		75,420		75,789		102,191		102,191	5.50%	(6)	5,620		5,620
420	587	587038	Customer Facilities Expense		71,021		34,482		63,486		25,949		56,508		56,508	5.50%	(6)	3,107		3,107
421	587	587126	Complaint Test		52,247		62,063		76,017		69,550		95,494		95,494	5.50%	(6)	5,251		5,251
422	587	587146	Current Diversions		475		(367)		4,985		3,210		4,979		4,979	5.50%	(6)	274		274
423	587	587147	Meter Base Repair		1,517		8,601		2,762		9,535		4,026		4,026	5.50%	(6)	221		221
424	587	587148	Customer Co-Gen Facilities		(8,078)		(20,037)		(13,987)		(12,081)		(18,871)		(18,871)	5.50%	(6)	(1,038)		(1,038)
425	587	587519	Location-Radio & Tv Interfer		-		6,881		3,805		5,499		1,296		1,296	5.50%	(6)	71		71
426	588	588011	Conv & Seminar-Misc Distrib		90,805		77,343		62,303		61,784		78,389		78,389	5.50%	(6)	4,311		4,311
427	588	588023	Building Operations - Expenses		741,012		572,804		493,268		488,855		492,147		492,147	5.50%	(6)	27,063		27,063
428	588	588025	Safety Equipment		413,086		311,421		291,189		288,805		272,668		272,668	5.50%	(6)	14,994		14,994
429	588	588046	Micro Software - Misc Dist		130		-								-	5.50%	(6)	-		-
430	588	588100	Miscellaneous Distribution		26,007		382,344		287,774		389,521		308,981		308,981	5.50%	(6)	16,991		16,991
431	588	588101	Janitorial Exp - Meter Shop		1,465		185		29				20		20	5.50%	(6)	1		1
432	588	588105	Utilities - Meter Shop		1,503		1,443		817		1,176		724		724	5.50%	(6)	40		40
433	588	588120	Misc Dist - Right-of-way		60,594		42,304		60,476		44,108		86,852		86,852	5.50%	(6)	4,776		4,776
434	588	588130	Misc Dist. - Joint Use		75,777		71,545		75,481		75,842		71,943		71,943	5.50%	(6)	3,956		3,956
435	588	588305	Utilities - MO Steel		12,492		9,175		2,967		8,701				-	5.50%	(6)	-		-
436	588	588401	Janitorial Exp - Garage		8,907		4,554		865		869		590		590	5.50%	(6)	32		32
437	588	588405	Utilities - Garage		858		863		845		784		810		810	5.50%	(6)	45		45
438	588	588501	Janitorial Exp - 4Th & Rr		2,823		23		121		121				-	5.50%	(6)	-		-
439	588	588505	Utilities - 4Th & Rr		774		843		204		698				-	5.50%	(6)	-		-
440	588	588621	GIS Operations		173,638		195,462		75,921		142,838		62,469		62,469	5.50%	(6)	3,435		3,435
441	588	588622	GIS Quality Assurance/Control		-		-		6,436		3,463		7,470		7,470	5.50%	(6)	411		411
442	588	588623	GIS Analysis		-		-		21,170		6,418		33,163		33,163	5.50%	(6)	1,824		1,824
443	588	588630	OMS Operations		96,608		108,957		119,847		119,866		115,693		115,693	5.50%	(6)	6,362		6,362
444	589	589034	Rents - Distribution		2,272		2,531		2,766		3,486		2,302		2,302	5.50%	(6)	127		127
445	590	590001	Supervision Distribution Maint		110,961		91,011		93,622		93,586		89,380		89,380	5.50%	(6)	4,915		4,915
446	590	590620	GIS Maintenance/Updates						46,192		32,118		25,627		25,627	5.50%	(6)	1,409		1,409
447	590	590630	Line Eng Distribution Maint	#	128,780	@	129,855	%	129,157	^	125,915	*	152,731		152,731	5.50%	(6)	8,399		8,399
448	591	591024	Building Maint-Line Operations		27,648		34,940		63,958		50,872		81,042		81,042	5.50%	(6)	4,457		4,457
449	591	591049	Dist Substa Structure Maint		15,876		12,008		5,881		8,724		7,162		7,162	5.50%	(6)	394		394
450	591	591103	General Maint. - Meter Shop		72		-		171		171				-	5.50%	(6)	-		-
451	591	591403	General Maint. - Garage		7,010		8,050		1,735		3,183		3,298		3,298	5.50%	(6)	181		181
452	591	591503	General Maint. - 4Th & Rr		1,487		112		49		49				-	5.50%	(6)	-		-
453	592	592052	Dist Substation Equip Maint		1,475,799		1,194,676		888,849		1,056,036		1,125,395		1,125,395	5.50%	(6)	61,886		61,886
454	592	592053	Dist Sub Breaker Routine Mtce		-		105,358		144,509		144,230		140,231		140,231	5.50%	(6)	7,711		7,711
455	592	592054	Dist Sub Trnsfrmr Routine Mtce		-		380,652		383,057		579,169		224,796		224,796	5.50%	(6)	12,362		12,362
456	592	592060	Dist Substation Inspections		291,393		214,105		229,911		216,422		206,883		206,883	5.50%	(6)	11,377		11,377
457	592	592469	Distribution-Relays & Misc Eq		78,115		87,334		74,666		91,578		85,545		85,545	5.50%	(6)	4,704		4,704
458	593	593001	OH Dist Line Tree Trimming Spr		1,023,684		1,020,448		1,102,101		1,075,716		1,033,882		1,033,882	5.50%	(6)	56,854		56,854
459	593	593011	Conv & Seminar - Tree Trimming		8,675		5,676		11,587		8,582		7,236		7,236	5.50%	(6)	398		398
460	593	593025	Safety Expense - Tree Trimming		1,004		341		1,186		357		2,132		2,132	5.50%	(6)	117		117
461	593	593058	Oh Dist Line Tree Trimming		4,094,609		3,379,502		2,920,039		2,974,803		3,196,561		3,196,561	5.50%	(6)	175,781		175,781
462	593	593062	Dist OH reliab - labor & other		228,104		208,757		294,267		258,766		270,966		270,966	5.50%	(6)	14,901		14,901
463	593	593158	Chemical Tree Trim 12Kv		732,659		989,674		1,390,186		1,026,192		1,705,413		1,705,413	5.50%	(6)	93,782		93,782
464	593	593258	Side Trimming 12Kv		289,759		142,976		129,380		202,907		78,059		78,059	5.50%	(6)	4,292		4,292

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
465	593	593458	Hydro-Ax Tree Trimming 12 Kv		153,718		1,075,236		967,085		1,206,808		843,352		843,352	5.50%	(6)	46,376		46,376
466	593	593500	Misc Repair Expense		9,635		6,966		9,885		10,611		8,737		8,737	5.50%	(6)	480		480
467	593	593510	General Office Expense		47,256		107,476		107,741		99,874		74,342		74,342	5.50%	(6)	4,088		4,088
468	593	593555	Oh Dist Line Maintenance		2,999,409		2,696,200		2,190,185		2,750,223		2,221,991		2,221,991	5.50%	(6)	122,188		122,188
469	593	593556	OhDist Line Capacitor BankMtce		-		80,955		100,816		156,823		19,544		19,544	5.50%	(6)	1,075		1,075
470	593	593558	Tree Grinder-Tree Trim 12kv		1,282,662		669,991		526,589		403,097		390,582		390,582	5.50%	(6)	21,478		21,478
471	593	593560	OH Dist Line Oper Storms		10,796		1,084		8,701		3,109		5,729		5,729	5.50%	(6)	315		315
472	593	593570	Reclosers Sect & Oil Switches		67,102		65,768		116,664		107,950		88,751		88,751	5.50%	(6)	4,880		4,880
473	593	593575	Misc Repair & Testing		48,841		38,808		40,384		32,879		34,476		34,476	5.50%	(6)	1,896		1,896
474	593	593597	May 2011 Tornado O&M Amort		84,402		84,402		84,402		84,402		84,402		84,402	0.00%	(1)	-		-
475	593	593598	2009 Wind Storm Amortization		92,153		4,956				2,478				-	0.00%	(1)	-		-
476	593	593599	Amortization-ice storm expense		157,445		139,909		132,681		132,681		132,681		132,681	100.00%	(1)	132,681		132,681
477	593	593658	Dozer-Tree Trim 12kv		43,719		8,381		14,193		6,379		10,990		10,990	5.50%	(6)	604		604
478	593	593740	TGR Tree Trimming-Distribution		531,805		954,657		594,479		848,340		922,502		922,502	5.50%	(6)	50,729		50,729
479	593	593910	OH Dist Line Maint Reliability		578,354		979,919		590,220		1,008,294		605,822		605,822	5.50%	(6)	33,314		33,314
480	593	593920	OH Dist Pole Inspc Reliability		500,171		617,263		556,762		464,580		819,654		819,654	5.50%	(6)	45,073		45,073
481	593	593930	General Office Exp Reliability		(716)		787		15		7		30		30	5.50%	(6)	2		2
482	593	593931	Janitor/Bldg Maint-Reliability		12		-								-	5.50%	(6)	-		-
483	593	593932	Utilities Exp - Reliability		2,556		3,585		3,493		3,435		4,047		4,047	5.50%	(6)	223		223
484	593	593940	Reliability Wildlife Cover Up		-		106,574		11,694		113,956		4,335		4,335	5.50%	(6)	238		238
485	593	593998	Dist OH Reliab Reg Adj Amort		1,149,480		667,972		357,478		423,931		357,478		357,478	0.00%	(1)	-		-
486	593	593999	Dist OH Reliability Reg Adj		1,396,039		(479,914)				(479,914)				-	5.50%	(6)	-		-
487	594	594061	Underground Dist Line Maint		690,478		590,184		468,554		577,966		424,770		424,770	5.50%	(6)	23,358		23,358
488	594	594062	Dist UG reliab - labor & other		19,034		20,540		22,798		23,676		23,242		23,242	5.50%	(6)	1,278		1,278
489	594	594910	Dist UG Line Maint Reliability		157,843		160,950		169,408		182,143		166,578		166,578	5.50%	(6)	9,160		9,160
490	594	594998	Dist UG Reliab Reg Adj Amort		55,172		31,808		17,023		20,187		17,023		17,023	0.00%	(1)	-		-
491	594	594999	Dist UG Reliability Reg Adj		53,709		(22,853)				(22,853)				-	5.50%	(6)	-		-
492	595	595064	Dist Transformer Maintenance		2,815		1,900		5,108		4,001		3,797		3,797	5.50%	(6)	209		209
493	595	595161	Overhead Transformers - Old		398,935		409,854		402,759		412,026		388,455		388,455	5.50%	(6)	21,361		21,361
494	595	595164	Underground Transformers - Old		44,716		34,462		37,375		39,908		37,540		37,540	5.50%	(6)	2,064		2,064
495	596	596067	Strt Light&Signal Sys Maint Ex		365,857		304,686		318,133		311,332		303,822		303,822	5.50%	(6)	16,707		16,707
496	597	597123	Shop Test & Repair		332,139		304,964		328,164		327,468		312,931		312,931	5.50%	(6)	17,208		17,208
497	597	597138	Load Research Equipment Repair		23,113		29,293		40,776		32,546		41,483		41,483	5.50%	(6)	2,281		2,281
498	598	598073	Maint Of Misc Distrib Plant		255,240		227,331		268,086		215,477		244,291		244,291	5.50%	(6)	13,434		13,434
499			**Total Distribution Expenses:**		**29,022,564**		**26,992,608**		**24,890,648**		**26,307,233**		**25,438,528**	**-**	**25,438,528**			**1,499,028**	**-**	**1,499,028**
CUSTOMER ACCOUNT EXPENSES																				
500	901	901001	Customer Service Mgmt & Admin	#	351,654	@	453,758	%	636,418	^	556,177	*	655,804		655,804	5.61%	(7)	36,760		36,760
501	901	901002	Cust Ser Mgmt & Admin - Exp		20,133		21,248		17,045		19,273		16,166		16,166	5.61%	(7)	906		906
502	901	901011	Conv & Seminar-Cust Accts Dist		11,254		20,929		13,470		20,162		12,557		12,557	5.61%	(7)	704		704
503	901	901025	Safety Exp-Customer Service		748		707		705		876		397		397	5.61%	(7)	22		22
504	901	901042	Outside Printing-Customer Serv		8,050		10,195		8,825		9,017		7,939		7,939	5.61%	(7)	445		445
505	901	901201	Mgmt & Administrative - Accoun		78,138		68,916		75,862		68,526		81,164		81,164	5.61%	(7)	4,550		4,550
506	902	902005	Check Meter Reads - Electric		8,118		15,074		33,048		20,097		57,273		57,273	5.61%	(7)	3,210		3,210
507	902	902007	Read Meters - Electric		1,929,666		1,972,860		2,011,037		1,990,343		1,982,726		1,982,726	5.61%	(7)	111,138		111,138
508	903	903002	Collection Activities - Gas						675				1,422		1,422	5.61%	(7)	80		80
509	903	903013	Power Billing		5,996		3,816		4,716		2,739		5,362		5,362	5.61%	(7)	301		301
510	903	903016	Collection Activities - Elec		273,328		219,768		182,275		180,522		153,922		153,922	5.61%	(7)	8,628		8,628
511	903	903022	Cust Serv Accounting - Ele/Gas		1,848,270		1,710,676		1,692,356		1,698,647		1,757,977		1,757,977	5.61%	(7)	98,540		98,540
512	903	903023	Remittance Processing		114,738		82,266		114,040		84,576		139,279		139,279	5.61%	(7)	7,807		7,807
513	903	903028	Credit & Collections		234,476		200,904		163,830		164,844		172,675		172,675	5.61%	(7)	9,679		9,679
514	903	903046	Micro Software-Rev Acct		3		718		588		686		361		361	5.61%	(7)	20		20
515	903	903110	Billing Of Metered Accts-Elec		1,253,871		1,251,489		1,190,936		1,204,114		1,199,574		1,199,574	5.61%	(7)	67,240		67,240
516	903	903146	Collectors' Fees		119,062		136,573		140,377		143,609		132,391		132,391	5.61%	(7)	7,421		7,421
517	903	903148	Banking Fees - Mercantile		6,057		5,254		5,900		5,611		6,430		6,430	5.61%	(7)	360		360
518	903	903150	Rating Agency Fees		229,898		196,977		149,860		192,640		146,034		146,034	5.61%	(7)	8,186		8,186
519	903	903151	Banking Fees - UMB		145,193		116,676		116,039		117,581		116,381		116,381	5.61%	(7)	6,524		6,524
520	904	904037	Uncollectible Accts-Electric		1,791,218		1,400,395		1,664,572		1,566,793		1,984,992		1,984,992	5.61%	(7)	111,265		111,265
521	904	904038	Uncollect - Misc Receivables		311		-								-	5.61%	(7)	-		-
522	905	905023	Building Operations-Cust Accts		105,102		82,894		74,791		82,415		88,028		88,028	5.61%	(7)	4,934		4,934
523	905	905031	General Office Exp-Cust Acct		5,281		6,108		10,738		7,107		9,062		9,062	5.61%	(7)	508		508
524	905	905032	Phone Directory Expense		14,455		19,235		17,667		16,013		16,357		16,357	5.61%	(7)	917		917
525	905	905042	Outages		716		483		1,569		1,673		55		55	5.61%	(7)	3		3
526	905	905045	Cyber Insurance		68,551		63,714		26,416		51,039		9,993		9,993	5.61%	(7)	560		560
527			**Total Customer Account Expenses:**		**8,624,288**		**8,061,632**		**8,353,756**		**8,205,081**		**8,754,321**	**-**	**8,754,321**			**490,707**	**-**	**490,707**
CUSTOMER ASSISTANCE EXPENSES																				
528	907	907101	Customer Service Supervision	#	160,529	@	136,054	%	204,534	^	188,751	*	207,128		207,128	5.61%	(7)	11,610		11,610
529	908	908011	Out-Of-Area Convention/Seminar		-		289								-	5.61%	(7)	-		-
530	908	908043	Customer Assistance-Cust Serv		178,693		127,575		153,968		134,955		149,539		149,539	5.61%	(7)	8,382		8,382
531	908	908046	Micro Software-Mjr Accts		-		672		920		195		920		920	5.61%	(7)	52		52
532	908	908101	Retail Indust Cust Assistance		378,993		395,087		398,833		407,154		423,504		423,504	5.61%	(8)	23,739		23,739
533	908	908103	Cust Prog Collaborative Exp		1,043,182		1,313,708		1,587,160		1,449,974		1,612,408		1,612,408	0.00%	(1)	-		-

Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
534	908	908104	Wholesale Customer Assistance		33,447		41,102		73,102		39,570		114,690		114,690	0.00%	(8)	-		-
535	908	908106	Retail Commercial Cust Assist		547,594		525,619		451,012		532,509		449,236		449,236	5.61%	(8)	25,182		25,182
536	908	908107	Retail Residential Cust Assist		253,430		243,904		208,402		248,098		198,109		198,109	5.61%	(8)	11,105		11,105
537	908	908108	Low Income Weatherization Prgm		(375)		-						368		368	5.61%	(8)	21		21
538	908	908113	DSM Implementation		257		-								-	0.00%	(1)	-		-
539	908	908114	Net Metering/Cogen Activities		69,953		(168)								-	0.00%	(1)	-		-
540	908	908116	MO Low Inc Weather ER2014-0351		94,855		140,961		188,198		109,204		203,994		203,994	0.00%	(1)	-		-
541	908	908117	Solar Rebate Amrt ER-2016-0023		-		180,849		620,055		490,876		620,055		620,055	0.00%	(1)	-		-
542	908	908120	Energy Efficiency Cost Recover		22,754		56,453		12,319		38,239		36,707		36,707	0.00%	(1)	-		-
543	908	908123	KS En Eff 10-EPDE-497-TAR		8,936		5,003				5,003				-	0.00%	(1)	-		-
544	908	908124	Dem Side Mgmt Rider OK		-		5,010		99		5,010		99		99	0.00%	(1)	-		-
545	909	909116	E.D. Advertising		106		2,000		2,490		2,495		1,994		1,994	5.61%	(7)	112		112
546	909	909231	Info & Instruct Ad - Radio		52,942		53,745		26,544		34,096		20,291		20,291	5.61%	(7)	1,137		1,137
547	909	909232	Info & Instruct Ad - Tv		75,393		84,104		45,498		54,141		36,322		36,322	5.61%	(7)	2,036		2,036
548	909	909233	Info & Instruct Ad - Newsppr		48,552		40,271		39,277		34,591		43,752		43,752	5.61%	(7)	2,452		2,452
549	909	909235	Info & Instruct Ad-Schl Pub		200		-		-		-				-	5.61%	(7)	-		-
550	909	909236	Info & Instruct Ad - Other		4,063		8,020		3,575		7,820		7,600		7,600	5.61%	(7)	426		426
551	909	909316	Other Promotion		-		-		4,394		4,394				-	5.61%	(7)	-		-
552	910	910008	Cust Serv & Public Info-Cler		12,524		11,034		15,428		12,760		17,440		17,440	5.61%	(7)	978		978
553			**Total Customer Assistance Expenses:**		2,986,029		3,371,292		4,035,808		3,799,833		4,144,157	-	4,144,157			87,232	-	87,232
SALES EXPENSE																				
554	912	912002	Municipal Activities	#	13,465	@	7,847	%	13,246	^	7,804	*	12,760		12,760	4.30%	(9)	548		548
555	912	912011	Conferences		13,122		10,388		7,068		9,539		3,437		3,437	4.30%	(9)	148		148
556	912	912025	New Business-Cust Serv		158,232		126,623		127,427		131,311		127,182		127,182	4.30%	(9)	5,465		5,465
557	912	912113	Ed Admin-Labor Veh & Other		9,863		8,815		10,340		5,696		10,340		10,340	4.30%	(9)	444		444
558	912	916046	Micro Software-Sales		-		101				(18)				-	4.30%	(9)	-		-
559			**Total Sales Expenses:**		194,682		153,774		158,081		154,331		153,719	-	153,719			6,605	-	6,605
RESEARCH AND DEVELOPMENT																				
560	930	930232	**Total Research and Development:**	#	-	@	-	%	-	^	-	*	-	-	-			-	-	-
ADMINISTRATIVE AND GENERAL EXPENSES																				
561	928	928000	Regulatory Commission Exp-Corp	#	1,398,638	@	1,208,653	%	1,340,377	^	1,245,552	*	1,321,445		1,321,445		(1)	103,350		103,350
562	928	928002	FERC Gen Formula Rate Case Exp	#	3,676	@	-	%	-	^	-	*			-			-		-
563	928	928003	FERC Tran Formula Rate Case Ex	#	11,822	@	5,279	%	-	^	-	*			-			-		-
564			**Total Administrative and General Expenses:**		1,414,137		1,213,932		1,340,377		1,245,552		1,321,445	-	1,321,445			103,350	-	103,350
OTHER ADMINISTRATIVE AND GENERAL EXPENSES																				
565	920	920101	Mgmt & Admin - Executives	#	2,564,365	@	3,151,443	%	833,291	^	2,305,821	*	486,175		486,175	4.24%	(10)	20,610		20,610
566	920	920102	Mgmt Incentive - LTIP		-		-		62,559				164,523		164,523	4.24%	(10)	6,974		6,974
567	920	920103	Executive Performance Shares		929,141		2,183,137				1,536,706				-	4.24%	(10)	-		-
568	920	920104	Restricted Stock Awards		328,710		741,204				209,681					4.24%	(10)	-		-
569	920	920109	Mgmt & Adm Salaries-Spec Proj		-		-		10,824		4,967		(5,884)		(5,884)	4.24%	(10)	(249)		(249)
570	920	920112	LUC Labor Allocs		-		-		377,636		201,325		486,967		486,967	4.24%	(10)	20,643		20,643
571	920	920130	M&A Transf Work Gas-GL001 Only		-		-		(354)				(354)		(354)	4.24%	(10)	(15)		(15)
572	920	920201	Mgmt & Admin - Salaries-Acct		494,216		591,151		418,525		527,109		388,160		388,160	4.24%	(10)	16,455		16,455
573	920	920212	APUC Labor Allocs		-		-		1,655,469		629,252		1,616,404		1,616,404	4.24%	(10)	68,522		68,522
574	920	920261	General Recordsaccounting		483,649		537,058		581,939		536,416		626,391		626,391	4.24%	(10)	26,554		26,554
575	920	920264	Accounts Payable-Accounting		143,243		153,469		168,472		162,433		167,578		167,578	4.24%	(10)	7,104		7,104
576	920	920301	Mgmt & Admin - Field Safety Ad		507,534		526,095		559,734		527,609		519,382		519,382	4.24%	(10)	22,017		22,017
577	920	920312	LUSC BS Labor Allocs		-		-		-		-		143,747		143,747	4.24%	(10)	6,094		6,094
578	920	920412	LABS CAN BS Labor Allocs		-		-		886,264		337,342		1,483,326		1,483,326	4.24%	(10)	62,880		62,880
579	920	920413	LABS BS Labor Allocs-Electric		-		-		-		-		99,619		99,619	4.24%	(10)	4,223		4,223
580	920	920449	Mgmt & Admini - Salaries-Info		792,427		757,407		44,140		430,620		(19,737)		(19,737)	4.24%	(10)	(837)		(837)
581	920	920450	Personnel - Salary - Info Serv		1,829,792		1,863,010		423,122		1,386,802		(28,877)		(28,877)	4.24%	(10)	(1,224)		(1,224)
582	920	920455	Personnel - Hourly - Info Serv		-		1,570		4,741		4,741				-	4.24%	(10)	-		-
583	920	920501	Mgmt & Admini - Salaries-Hr		248,232		263,095		97,277		217,652		(18,080)		(18,080)	4.24%	(10)	(766)		(766)
584	920	920503	Payroll Activi-Labor Only-Hr		143,862		155,219		115,816		138,635		46,417		46,417	4.24%	(10)	1,968		1,968
585	920	920504	Personnel Activi-Lbr Only-Hr		221,450		241,053		142,507		211,285		103,115		103,115	4.24%	(10)	4,371		4,371
586	920	920505	Train Program Dev - Labor-Hr		65,628		67,635		63,552		68,717		23,484		23,484	4.24%	(10)	996		996
587	920	920512	LABS CAN CS Labor Allocs		-		-		1,795,983		378,842		2,200,187		2,200,187	4.24%	(10)	93,269		93,269
588	920	920513	LABS CS Labor Allocs-Electric		-		-		-		-		130,397		130,397	4.24%	(10)	5,528		5,528
589	920	920601	Mgmt & Admin-General Services		139,285		137,982		246,392		227,157		173,807		173,807	4.24%	(10)	7,368		7,368
590	920	920612	LABS US BS Labor Allocs		-		-		2,895		911		1,984		1,984	4.24%	(10)	84		84
591	920	920615	Purchasing Activities-Gen Serv		79,636		128,424		143,472		140,288		142,229		142,229	4.24%	(10)	6,029		6,029
592	920	920623	Janitorial Serv-Labor-Gen Serv		15,436										-	4.24%	(10)	-		-
593	920	920666	Receive & Deliver Company Mail		18,993		19,961		20,324		20,339		18,086		18,086	4.24%	(10)	767		767
594	920	920669	General Service Activities		60,055		57,791		46,150		53,858		44,096		44,096	4.24%	(10)	1,869		1,869
595	920	920701	Mgmt & Admin-Sal-Other Gen Off		1,627,319		1,515,503		572,745		1,197,778		275,733		275,733	4.24%	(10)	11,689		11,689
596	920	920703	Reporting Activities - Gen Off		546,451		469,451		383,257		447,741		345,429		345,429	4.24%	(10)	14,643		14,643
597	920	920715	LABS US CS Labor Allocs		-		-		14,157		554		13,603		13,603	4.24%	(10)	577		577
598	920	920721	Load Research		100,378		108,838		85,465		109,462		38,856		38,856	4.24%	(10)	1,647		1,647

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
599	920	920750	Mgmt & Admin - Land Rights		79,578		77,088		129,045		90,599		137,008		137,008	4.24%	(10)	5,808		5,808
600	920	920799	Transfer Acct for BU Errors		-		-		(2)		(0)		(2)		(2)	4.24%	(10)	(0)		(0)
601	920	920812	CENTRAL Labor Allocs		-		-		158,078		41,691		204,308		204,308	4.24%	(10)	8,661		8,661
602	920	920813	Central OC Labor Allocs-Electr		-		-		-		-		113,752		113,752	4.24%	(10)	4,822		4,822
603	920	920881	MO Renewable Energy Std Labor		196,727		291,056		127,532		147,299		118,736		118,736	0.00%	(1)	-		-
604	920	920882	Administrative & General Sal		77,908		142,413		82,801		121,921		52,540		52,540	4.24%	(10)	2,227		2,227
605	920	920883	KS Renewable Energy Std Labor		-		750		3,616		1,515		4,964		4,964	100.00%	(1)	4,964		4,964
606	920	920912	LIB CORP US Labor Allocs		-		-		2,688		2,688		108,435		108,435	4.24%	(10)	4,597		4,597
607	921	921050	Ap Vendor Discount		-		(2,625)		(3,727)		(6,353)				-	4.24%	(10)	-		-
608	921	921102	Mgmt & Admin-Exp-Executives		234,561		203,747		116,160		159,448		76,916		76,916	4.24%	(10)	3,261		3,261
609	921	921103	SPP Administrative Expenses		5,517		10,126		4,356		7,016		4,099		4,099	4.24%	(10)	174		174
610	921	921104	United Way Expenses		13,763		9,074		(4,576)		9,074		7,491		7,491	4.24%	(10)	318		318
611	921	921105	Employee Engagement Program		-		-		648				648		648	4.24%	(10)	27		27
612	921	921111	M&A Expenses - Util Planning		-		-		10,898		1,906		28,613		28,613	4.24%	(10)	1,213		1,213
613	921	921112	LUC Other Allocs	#	-	@	-	%	86,995	^	85,615	*	48,227		48,227	4.24%	(10)	2,044		2,044
614	921	921202	Mgmt & Admin-Accounting		51,619		162,087		45,863		167,539		50,979		50,979	4.24%	(10)	2,161		2,161
615	921	921211	Conv & Seminar-Acct		19,138		41,588		14,391		33,004		5,001		5,001	4.24%	(10)	212		212
616	921	921212	APUC CS Other Allocs		-		-		32,459		32,459				-	4.24%	(10)	-		-
617	921	921225	Safety Expenses-Accounting		1,251		705		2,349		2,202		1,294		1,294	4.24%	(10)	55		55
618	921	921246	Micro Software-Acct		47,167		27,788		79,945		85,234		34,496		34,496	4.24%	(10)	1,462		1,462
619	921	921300	Pcb Oil & Used Oil		1,522		1,345		1,791		916		1,658		1,658	4.24%	(10)	70		70
620	921	921301	Mgmt & Admin - Exp - Field Saf		44,580		35,832		165,759		133,971		91,127		91,127	4.24%	(10)	3,863		3,863
621	921	921305	Required Certification Expense		981		574		811		587		1,201		1,201	4.24%	(10)	51		51
622	921	921306	Professional Membership & Dues		2,818		3,412		3,093		2,764		2,120		2,120	4.24%	(10)	90		90
623	921	921311	Conv & Seminars - Envir&Safety		4,306		5,684		1,837		3,667		3,674		3,674	4.24%	(10)	156		156
624	921	921312	LUSC BS Other Allocs		5,718		9,228		9,412		8,304		92		92	4.24%	(10)	4		4
625	921	921325	Misc Environmental Expenses										8,292		8,292	4.24%	(10)	352		352
626	921	921402	Return Postage		139		43		23		22		320		320	4.24%	(10)	14		14
627	921	921403	Offsite Expenses		7,153		9,629		2,418		7,743		1,426		1,426	4.24%	(10)	60		60
628	921	921411	Conv & Seminar-Computer Serv		42,361		39,234		67,735		53,566		54,754		54,754	4.24%	(10)	2,321		2,321
629	921	921412	LABS CAN BS Other Allocs		-		-		473,788		194,860		360,700		360,700	4.24%	(10)	15,291		15,291
630	921	921413	LABS BS Other Allocs-Electric		-		-		-		-		1,351		1,351	4.24%	(10)	57		57
631	921	921446	Micro Software-Info Serv		31,303		31,303		31,303		31,303		31,303		31,303	4.24%	(10)	1,327		1,327
632	921	921449	Mgmt & Admin Exp - Info Serv		10,812		7,273		10,556		15,703		(3,927)		(3,927)	4.24%	(10)	(166)		(166)
633	921	921450	Personnel Exp - Info Services		5,802		2,340		2,717		1,465		1,252		1,252	4.24%	(10)	53		53
634	921	921469	Hardware Purchases		2,015		10,926		28,090		36,643		5,319		5,319	4.24%	(10)	225		225
635	921	921470	Hardware Maintenance		267,474		291,935		168,423		346,657		37,980		37,980	4.24%	(10)	1,610		1,610
636	921	921471	Software Purchases		125,540		36,146		36,454		19,234		32,512		32,512	4.24%	(10)	1,378		1,378
637	921	921473	Data Processing Supplies		13,270		24,604		5,090		12,420		3,431		3,431	4.24%	(10)	145		145
638	921	921474	Software Maintenance		1,070,713		1,230,843		1,209,316		1,439,722		851,138		851,138	4.24%	(10)	36,081		36,081
639	921	921475	Telecommunications		21,411		27,528		20,316		24,028		17,169		17,169	4.24%	(10)	728		728
640	921	921484	Manuals		67		59		65		133		(10)		(10)	4.24%	(10)	(0)		(0)
641	921	921489	Supplies-Other		4,925		4,464		11,966		8,274		8,151		8,151	4.24%	(10)	346		346
642	921	921502	Mgmt & Administrative - Exp-Hr		35,325		41,348		56,391		50,066		42,231		42,231	4.24%	(10)	1,790		1,790
643	921	921506	Train Program Devel-No Lab-Hr		7,610		12,818		474		9,100		474		474	4.24%	(10)	20		20
644	921	921511	Conv & Seminar-No Labor		2,047		896		633		100		633		633	4.24%	(10)	27		27
645	921	921512	LABS CAN CS Other Allocs		-		-		606,731		127,554		705,391		705,391	4.24%	(10)	29,903		29,903
646	921	921513	LABS CS Other Allocs-Electric		-		-		-		-		6,860		6,860	4.24%	(10)	291		291
647	921	921516	Recruiting - No Labor-Hr		9,290		9,119		6,515		5,096		4,226		4,226	4.24%	(10)	179		179
648	921	921602	Mgmt & Admin-Exp		36,748		37,164		36,487		38,272		29,265		29,265	4.24%	(10)	1,241		1,241
649	921	921603	General Office Matrls & Sup		1,898		1,516		3,445		1,188		3,018		3,018	4.24%	(10)	128		128
650	921	921611	Conv & Seminar-Gen Office		654		802		1,139		1,272		751		751	4.24%	(10)	32		32
651	921	921612	LABS US BS Other Allocs		-		-		825				825		825	4.24%	(10)	35		35
652	921	921620	Record Retention - Other		2,866		2,627		3,871		3,848		2,414		2,414	4.24%	(10)	102		102
653	921	921625	Safety Exp-Bldg Serv		74,844		164		323		487		344		344	4.24%	(10)	15		15
654	921	921639	Janitorial Service - Expenses		13,294		75,171		85,697		83,961		85,529		85,529	4.24%	(10)	3,626		3,626
655	921	921648	Utilities		16,583		11,975		12,092		11,700		13,632		13,632	4.24%	(10)	578		578
656	921	921654	Printing Expenses		24,987		17,667		21,449		17,215		19,776		19,776	4.24%	(10)	838		838
657	921	921667	Rec & Del Company Mail - Exp		92,444		25,596		25,202		26,600		26,584		26,584	4.24%	(10)	1,127		1,127
658	921	921702	Mgmt & Admin - Expenses		1,175		114,880		130,216		127,913		123,279		123,279	4.24%	(10)	5,226		5,226
659	921	921703	Other General Office		20,592		710		185		224		309		309	4.24%	(10)	13		13
660	921	921711	Conv & Seminar-Fras		2,488		22,980		11,594		22,344		6,374		6,374	4.24%	(10)	270		270
661	921	921712	Education Expense		-		668		1,878		885		1,643		1,643	4.24%	(10)	70		70
662	921	921715	LABS US CS Other Allocs		-		-		566		566				-	4.24%	(10)	-		-
663	921	921717	Employee Clothing		801		(1,531)		(368)		(1,663)		(329)		(329)	4.24%	(10)	(14)		(14)
664	921	921720	Fuel & PP Forecasting Exp		790		25,346		5,992		13,346		5,992		5,992	4.24%	(10)	254		254
665	921	921721	Load Research Expenses		51,413		51,357				51,357		26,449		26,449	4.24%	(10)	1,121		1,121
666	921	921722	Financial Projection Exp		10,648		11,817				11,817				-	4.24%	(10)	-		-
667	921	921723	Forecasting - Other Expenses		-		-		5,691				5,691		5,691	4.24%	(10)	241		241
668	921	921750	Mgmt & Admin - Exp Land Rights		17,562		15,643		19,964		12,143		22,573		22,573	4.24%	(10)	957		957
669	921	921775	General Services Supplies		14,698		15,406		16,263		20,730		12,134		12,134	4.24%	(10)	514		514
670	921	921776	Microcomputer Supplies		6,085		3,690		1,943		2,662		656		656	4.24%	(10)	28		28
671	921	921812	CENTRAL Other Allocs		-		-		8,410		8,410		30,180		30,180	4.24%	(10)	1,279		1,279

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
672	921	921881	Renewable Energy Std Veh Exp		21,622		38,693		25,003		25,877		29,514		29,514	4.24%	(10)	1,251		1,251
673	921	921885	A&G Expenses Iatan		907,221		900,112		944,272		904,326		944,354		944,354	4.24%	(10)	40,032		40,032
674	921	921886	Home Off Support Travel & Misc		6,108		-		12				25		25	4.24%	(10)	1		1
675	921	921912	LIB CORP US Other Allocs		-		-		3,859		1,408		34,782		34,782	4.24%	(10)	1,474		1,474
676	922	922000	Admin Exp Transf - Credit		(1,484,098)		(1,841,034)		(891,207)		(1,503,998)		(646,315)		(646,315)	4.24%	(10)	(27,398)		(27,398)
677	922	922099	LABS US BS Reg Alloc Capitaliz		-		-		(106,274)		(106,274)				-	4.24%	(10)	-		-
678	922	922101	Transfer charges- Subsidiaries		(1,160,046)		(1,114,291)		(1,381,767)		(1,227,556)		(1,336,591)		(1,336,591)	4.24%	(10)	(56,660)		(56,660)
679	922	922185	Transfer Charges - WGI		(340,216)		(189,952)		(301,912)		(249,764)		(233,099)		(233,099)	4.24%	(10)	(9,881)		(9,881)
680	922	922199	LUC CAN BS Alloc Capitalized		-		-		(725,529)		(372,737)		(682,398)		(682,398)	4.24%	(10)	(28,928)		(28,928)
681	922	922299	APUC Corp CS Alloc Capitalized		-		-		(844,398)		(368,280)		(1,010,022)		(1,010,022)	4.24%	(10)	(42,816)		(42,816)
682	922	922399	LUSC BS Alloc Capitalized		-		-		-		-		(30,206)		(30,206)	4.24%	(10)	(1,280)		(1,280)
683	922	922499	LABS BS Capitalized		-		-		(282,420)		(111,824)		(383,993)		(383,993)	4.24%	(10)	(16,278)		(16,278)
684	922	922500	Non-Prod Indirect Work - ELabs		-		-		5,798		9,089		5,005		5,005	4.24%	(10)	212		212
685	922	922502	Services for LUC		-		-		-		-		-		-	4.24%	(10)	-		-
686	922	922503	Services for Labs Canada		-		-		1,057		879		1,205		1,205	4.24%	(10)	51		51
687	922	922504	Services for LUSC 8880		-		-		-		-				-	4.24%	(10)	-		-
688	922	922505	Services for E-Labs (US) 8885		-		-				-		15,838		15,838	4.24%	(10)	671		671
689	922	922506	Services for Labs (Labs US) GP		-		-		-		9,502		(9,502)		(9,502)	4.24%	(10)	(403)		(403)
690	922	922507	Services for Liberty Corp US		-		-		-		240		(240)		(240)	4.24%	(10)	(10)		(10)
691	922	922508	Services for APCO		-		-		4,415		11,339		(11,339)		(11,339)	4.24%	(10)	(481)		(481)
692	922	922510	Services for Sanger Power 5519		-		-		35		5,506		(5,506)		(5,506)	4.24%	(10)	(233)		(233)
693	922	922511	Services for Deerfield		-		-				312		(312)		(312)	4.24%	(10)	(13)		(13)
694	922	922512	Services for O'Dell								3,963		(3,963)		(3,963)	4.24%	(10)	(168)		(168)
695	922	922514	Services for Shady Oaks								960		(960)		(960)	4.24%	(10)	(41)		(41)
696	922	922515	Services for St. Leon								2,191		(2,191)		(2,191)	4.24%	(10)	(93)		(93)
697	922	922516	Services for Minonk		-		-				967		(967)		(967)	4.24%	(10)	(41)		(41)
698	922	922517	Services for Senate		-		-		144		340		(340)		(340)	4.24%	(10)	(14)		(14)
699	922	922599	LABS CAN CS Allocs Capitalized		-		-		(1,103,415)		(367,924)		(1,284,773)		(1,284,773)	4.24%	(10)	(54,463)		(54,463)
700	922	922600	Services for East 8882		-		-		-		-				-	4.24%	(10)	-		-
701	922	922601	Services for NH 8810		-		-				-				-	4.24%	(10)	-		-
702	922	922604	Services for GA/Peach St 8862		-		-				-				-	4.24%	(10)	-		-
703	922	922605	Services for N Eng/Mass 8866		-		-				-				-	4.24%	(10)	-		-
704	922	922699	LABS US BS Capitalized		-		-		(606,690)		(306,441)		(654,650)		(654,650)	4.24%	(10)	(27,752)		(27,752)
705	922	922700	Services for Central 8883		-		-		60,406		64,010		150,643		150,643	4.24%	(10)	6,386		6,386
706	922	922701	Services for Empire Consol								1,621		20,410		20,410	4.24%	(10)	865		865
707	922	922702	Services for Empire Elec 8905								1,399		(1,399)		(1,399)	4.24%	(10)	(59)		(59)
708	922	922704	Services for Empire Fiber 8915								18		(18)		(18)	4.24%	(10)	(1)		(1)
709	922	922705	Services for Pine Bluff 8606		-		-		-		9		168		168	4.24%	(10)	7		7
710	922	922706	Services for WHall Water 8608		-		-		-		8		(8)		(8)	4.24%	(10)	(0)		(0)
711	922	922708	Services for Mid States 8850	#	-	@	-	%	698	^	682	*	2,444		2,444	4.24%	(10)	104		104
712	922	922709	Services for Mid States Water		-		-		5				2,009		2,009	4.24%	(10)	85		85
713	922	922799	LABS US CS Capitalized		-		-		(15,918)		(13,963)		(1,986)		(1,986)	4.24%	(10)	(84)		(84)
714	922	922800	Services for West 8884		-		-		1,093		-		1,317		1,317	4.24%	(10)	56		56
715	922	922801	Services for Liberty Wtr 8020								-		47		47	4.24%	(10)	2		2
716	922	922802	Services for Calpeco 8800		-		-		-		788		6,218		6,218	4.24%	(10)	264		264
717	922	922803	Services for Park Water 8623										583		583	4.24%	(10)	25		25
718	922	922899	Central Allocs Capitalized		-		-		(322,636)		(73,285)		(533,215)		(533,215)	4.24%	(10)	(22,604)		(22,604)
719	922	922900	Indirect Liberty Corp US		-		-		969		6,361		(4,638)		(4,638)	4.24%	(10)	(197)		(197)
720	922	922999	Liberty Corp US CS Capitalized		-		-		(85,461)		(27,550)		(161,564)		(161,564)	4.24%	(10)	(6,849)		(6,849)
721	923	923010	LABS US BS Reg Indir Allocs		-		-		382,259		382,259				-	4.24%	(10)	-		-
722	923	923045	Outside Services		1,511,838		1,600,166		403,891		975,666		1,338,080		1,338,080	4.24%	(10)	56,723		56,723
723	923	923046	Outside Services - EDG Only		37,893		38,792		280		540		1,260		1,260	4.24%	(10)	53		53
724	923	923047	Outside Services - EDE Only		1,148,467		460,010		442,005		402,656		589,552		589,552	4.24%	(10)	24,992		24,992
725	923	923050	Management Fee		210,855		192,228		181,745		196,740		183,261		183,261	4.24%	(10)	7,769		7,769
726	923	923051	O&M Fee - NAES		36,787		38,311		58,287		69,853		48,990		48,990	4.24%	(10)	2,077		2,077
727	923	923110	LUC BS Indirect Allocs		-		-		3,100,672		1,598,401		2,714,319		2,714,319	4.24%	(10)	115,064		115,064
728	923	923145	Outside Serv - Liab Claims		46,064		43,362		87,071		50,421		143,506		143,506	4.24%	(10)	6,083		6,083
729	923	923154	Liab Claim Jason Hynes		(2,143)										-	4.24%	(10)	-		-
730	923	923175	Liab Claims - PAR ELECTRIC		128,791										-	4.24%	(10)	-		-
731	923	923177	Liab Claims - Shane Jackson		(60,823)		(17)								-	4.24%	(10)	-		-
732	923	923181	Liab Claims-Class Action-Rider		45,242										-	4.24%	(10)	-		-
733	923	923182	Liab Claims - Denker Asbestos		898		15,046		15,689		20,425		1,395		1,395	4.24%	(10)	59		59
734	923	923210	APUC CS Indirect Allocs		-		-		2,323,353		1,082,344		2,682,974		2,682,974	4.24%	(10)	113,735		113,735
735	923	923509	Outside Services - Training		44,121		6,713		9,058		11,799		11,688		11,688	4.24%	(10)	495		495
736	923	923510	LABS CAN CS Indirect Allocs		-		-		2,789,547		1,183,523		3,212,387		3,212,387	4.24%	(10)	136,178		136,178
737	923	923514	Outside Services - 401K Plan		1,646		76								-	4.24%	(10)	-		-
738	923	923610	LABS US BS Indirect Allocs		-		-		2,825,559		1,393,767		3,119,418		3,119,418	4.24%	(10)	132,236		132,236
739	923	923710	LABS US CS Indirect Allocs		-		-		75,124		65,370		9,754		9,754	4.24%	(10)	414		414
740	923	923810	CENTRAL Indirect Allocs		-		-		1,556,517		387,924		2,402,221		2,402,221	4.24%	(10)	101,834		101,834
741	923	923910	LIB Corp US CS Indirect Allocs		-		-		400,651		127,094		626,376		626,376	4.24%	(10)	26,553		26,553
742	924	924000	Property Insurance		3,106,055		3,057,769		2,929,419		2,975,613		2,596,344		2,596,344	4.24%	(10)	110,063		110,063
743	924	924001	Aviation Insurance		6,041		6,225		513		4,385		771		771	4.24%	(10)	33		33
744	925	925000	Injuries & Damages-Corp		1,209,403		1,517,385		1,006,949		1,410,661		1,002,401		1,002,401	4.24%	(10)	42,493		42,493

				Total Company												Kansas				
				Calendar Years Ended						Prior Test Year End		Test Year				Test Year				
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Reclass	Reclassed 06/30/2018 Balance	KS Allocation Factor		Kansas Ending Balance	Reclass	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)		(q) = (o) * (p)	(r)	(s) = (q) + (r)
745	926	926000	Benefits Contra Account		-		-		(408,276)		(255,696)		(239,271)		(239,271)	4.24%	(10)	(10,143)		(10,143)
746	926	926145	Pension SERP Defined Benefit		915,958		1,818,372		1,391,227		2,539,785		194,736		194,736	4.24%	(10)	8,255		8,255
747	926	926146	FAS 87 SLCC Reimbursement		(45,996)		(25,681)		3,266		(11,082)		142		142	4.24%	(10)	6		6
748	926	926147	FAS87 Reg Asset Amort Exp		(1,166,489)		(479,289)		1,203,932		93,227		1,685,032		1,685,032	4.24%	(10)	71,431		71,431
749	926	926148	FAS87 Pens - Elec/Gas (GAAP)		8,980,612		8,254,023		7,485,568		8,388,819		5,795,133		5,795,133	4.24%	(10)	245,664		245,664
750	926	926149	FAS87 Pens - Reg Asset (5yr)		611,310		620,746		594,495		603,101		(8,696)		(8,696)	4.24%	(10)	(369)		(369)
751	926	926197	Pensions - Iatan		1,097,607		1,178,365		1,169,189		1,202,342		1,191,361		1,191,361	4.24%	(10)	50,503		50,503
752	926	926201	Dental Plan		148,975		161,974		140,323		158,313		136,556		136,556	4.24%	(10)	5,789		5,789
753	926	926202	Vision Plan		46,518		50,491		44,415		49,650		42,072		42,072	4.24%	(10)	1,783		1,783
754	926	926212	Severence Benefits		-		-		-		-		525		525	4.24%	(10)	22		22
755	926	926214	Employee Refreshments		-		-		59,495		8,302		95,981		95,981	4.24%	(10)	4,069		4,069
756	926	926215	Comp Exp Employee Stk Purch		133,574		123,322		45,623		78,104		52,747		52,747	4.24%	(10)	2,236		2,236
757	926	926216	Employee Information		14,050		14,440		12,831		16,441		11,682		11,682	4.24%	(10)	495		495
758	926	926217	Flowers		2,581		2,489		1,349		2,058		1,272		1,272	4.24%	(10)	54		54
759	926	926218	Coffeeroom Supplies		5,990		6,599		9,718		6,251		13,141		13,141	4.24%	(10)	557		557
760	926	926219	Other Employee Benefits		61,862		82,212		79,523		96,471		77,343		77,343	4.24%	(10)	3,279		3,279
761	926	926222	Group Life Insurance		180,689		167,590		194,321		154,484		291,082		291,082	4.24%	(10)	12,339		12,339
762	926	926225	Executive Physicals		4,459		20,514		1,752		5,284		(148)		(148)	4.24%	(10)	(6)		(6)
763	926	926226	Employee Welfare Exp - Elec		66,210		70,344		10,444		37,637		20,952		20,952	4.24%	(10)	888		888
764	926	926227	Acc Death & Dismemb - Benefit		40,663		41,182		22,266		32,294		22,584		22,584	4.24%	(10)	957		957
765	926	926230	Flex Benefit Plan Expense		9,869		(17,919)		16,085		23,123		4,764		4,764	4.24%	(10)	202		202
766	926	926231	Tuition Reimbursement		42,465		47,051		38,661		41,065		41,976		41,976	4.24%	(10)	1,779		1,779
767	926	926232	Taxable Educational Assistance		(67)		(39)		4		(17)		(0)		(0)	4.24%	(10)	(0)		(0)
768	926	926326	FAS106 OPEB - Reg Amortization		(279,635)		(231,035)		(43,079)		(98,133)		(45,415)		(45,415)	4.24%	(10)	(1,925)		(1,925)
769	926	926327	FAS106 HC - Reg Asst Amort Exp		(1,281,202)		133,358		2,320,041		1,355,140		2,141,379		2,141,379	4.24%	(10)	90,776		90,776
770	926	926328	FAS106 HC - Elec/Gas (GAAP)		3,182,737		1,749,134		566,310		1,248,206		1,214,331		1,214,331	4.24%	(10)	51,477		51,477
771	926	926329	Healthcare - Electric/Gas		7,559,282		7,441,460		7,278,743		8,605,916		5,200,695		5,200,695	4.24%	(10)	220,465		220,465
772	926	926437	Employee Disability Plan Exp		122,343		114,053		134,998		123,743		126,321		126,321	4.24%	(10)	5,355		5,355
773	926	926555	401K - Electric/Gas		1,663,740		1,615,362		1,540,229		1,665,116		1,485,355		1,485,355	4.24%	(10)	62,966		62,966
774	929	929000	Duplicate Charges Credit		(207,453)		(273,295)		(276,978)		(298,353)		(276,657)		(276,657)	4.24%	(10)	(11,728)		(11,728)
775	930	930104	Franchise Elections		14,611		13,764		11,222		12,353		11,299		11,299	4.24%	(10)	479		479
776	930	930106	Local Advertising		353		245		176		176		420		420	4.24%	(10)	18		18
777	931	930141	Institutional Ad - Radio		1,735		420				420		2,000		2,000	4.24%	(10)	85		85
778	932	930143	Institutional Ad - Newspaper		713		-		1,425		425				-	4.24%	(10)	-		-
779	932	930144	Institutional Ad - Other		19		850		600		1,450				-	4.24%	(10)	-		-
780	933	930210	Industry Association Dues		177,740		204,233		193,355		202,505		219,686		219,686	4.24%	(10)	9,313		9,313
781	930	930219	E.D. Association Dues		8,777		8,515		6,515		8,435		7,095		7,095	4.24%	(10)	301		301
782	930	930220	Dir-Stkhldr & Oth Investor Exp		2,406,195		2,925,371		487,000		1,611,508		441,586		441,586	4.24%	(10)	18,719		18,719
783	930	930230	Conflict Resolution Hotline		3,431		3,444		3,719		7,163				-	4.24%	(10)	-		-
784	930	930234	Other		8,700		9,000								-	4.24%	(10)	-		-
785	930	930240	Misc Gen Exp-Other		17,754		18,077		16,104		10,348		40,198		40,198	4.24%	(10)	1,704		1,704
786	930	930248	Chamber Of Commerce Dues		41,698		39,389		18,765		19,059		20,138		20,138	4.24%	(10)	854		854
787	930	930298	External Merger Costs				8,219,220		5,871,677		14,090,897				-	4.24%	(10)	-		-
788	930	930299	Invest Adv Srv – Acquisition				863,062		32,844,057		25,058,969		238,751		238,751	0.00%	(11)	-		-
789	931	931026	Equipment Rental-Bld Serv		5,243		1,588		1,711		1,715		2,118		2,118	4.24%	(10)	90		90
790	931	931281	Building Rental		121,039		120,838		40,324		88,511		5,985		5,985	4.24%	(10)	254		254
791	935	935024	Building & Grounds Maintenance		202,169		234,235		227,234		205,072		250,608		250,608	4.24%	(10)	10,624		10,624
792	935	935026	Building Maintenance		217,023		284,924		284,832		309,155		285,006		285,006	4.24%	(10)	12,082		12,082
793	935	935027	Bldg Maint EDE owned rent prop		-		926		(17)		(9)		(6)		(6)	4.24%	(10)	(0)		(0)
794	935	935098	Computer Maintenance		15,356		19,898		15,584		19,871		15,978		15,978	4.24%	(10)	677		677
795	935	935099	Computer Mtce-Customer Watch		2		1		(0)		1				-	4.24%	(10)	-		-
796	935	935289	Supplies-Info Serv		8,209		(351)		(3)		(324)		2		2	4.24%	(10)	0		0
797	935	935346	Furniture Maintenance		2,041		423		32		339		35		35	4.24%	(10)	1		1
798	935	935347	Telephone System Maintenance		(11)		(6)		1		(3)		0		0	4.24%	(10)	0		0
799	935	935389	Office Equipment Maintenance		(806)		12		525		270		(4)		(4)	4.24%	(10)	(0)		(0)
800	935	935515	Microwave Maintenance Expenses		30,260		58,446		52,057		44,634		56,691		56,691	4.24%	(10)	2,403		2,403
801	935	935520	Telephone Expenses-Telecomm		286		1,669		570		843		280		280	4.24%	(10)	12		12
802	935	935523	Telecomm Exp Other		5,335		7,651		11,213		14,539		12,115		12,115	4.24%	(10)	514		514
803			**Total Other Administrative & General:**		44,795,029		57,395,788		90,654,322		92,227,626		49,138,232	-	49,138,232			2,072,638	-	2,072,638
804			**Total Electric Expenses:**		322,942,470		315,233,785		333,273,730		342,462,530		331,669,435	(10,995,421)	320,674,014			14,156,606	-	14,156,606
805			**Total Company Electric Expenses Allocation:**																	
806			**Total Electric Expenses per Trial Balance**		322,942,470		315,233,785		333,273,730		342,462,530		331,669,435	(10,995,421)	320,674,014			14,156,606		14,156,606
807	930	930298	External Merger Costs		-		(8,219,220)		(5,871,677)		(14,090,897)		-	-	-		(11)	-		-
808	930	930299	Invest Adv Srv – Acquisition		-		(863,062)		(32,844,057)		(25,058,969)		(238,751)	-	(238,751)		(11)	-		-
809			Total Electric Expense less Acquisition		322,942,470		306,151,503		294,557,997		303,312,664		331,430,684	(10,995,421)	320,435,264			14,156,606		14,156,606
810			4 State Report		322,942,470		306,151,484		294,557,997		303,312,664		331,430,684	(10,995,421)	320,435,264			14,156,606		14,156,606
811			Difference		$ (0)		$ 19		$ (0)		$ (0)		$ 0	$ 0	$ (0)			$ 0		$ 0

				Total Company													Kansas			
				Calendar Years Ended						Prior Test Year End		Test Year					Test Year			
Line No.	**FERC**	**GL Account**	**Description**	**Reference**	**12/31/2015**	**Reference**	**12/31/2016**	**Reference**	**12/31/2017**	**Reference**	**6/30/2017**	**Reference**	**6/30/2018**	**Reclass**	**Reclassed 06/30/2018 Balance**	**KS Allocation Factor**	**Kansas Ending Balance**	**Reclass**	**Adjusted Kansas Ending Balance**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o) = (m) + (n)	(p)	(q) = (o) * (p)	(r)	(s) = (q) + (r)

Footnotes:
(1) Direct Assigned to Jurisdiction
(2) Allocation WP-12-month KWH Sales Allocator
(3) Allocation MO/KS Deriv Inrecov Fuel - WP-12-month KWH Sales Allocator
(4) Allocation WP-12-month average peak
(5) Allocation SPP Fixed Charge WP-12-month average peak
(6) Allocation Distribution WP-Plant in Service
(7) Allocation Customer Accounts WP-Average Number of Customers
(8) Allocation Customer Assistance WP-Average Number of Customers
(9) Allocation Sales WP-Revenues
(10) Allocation Other Admin & General WP-Labor Allocator
(11) Per Stipulation Agreement disallow Acquisition Costs

Tickmarks:
= Traced and Agreed To 12/15 Trial Balance
@ = Traced and Agreed To 12/16 Trial Balance
% = Traced and Agreed To 12/17 Trial Balance
^ = Traced and Agreed To 6/30/17 Trial Balance
* = Traced and Agreed To 06/30/18 Trial Balance

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	401		**Operation Expense**											
2			**Iatan/Plum Pt Deferred Operating Expenses:**											
3	421	421022	MO Iat I Amrt O&M ER-2010-0130	#	$ 35,725	@	$ 35,691	%	$ 31,111	^	$ 33,372	*	$ 33,587	$ -
4	421	421025	KS PlumPt DfOM 10-EPDE-314-RTS		42,949		-		-		-		-	
5	421	421026	KS Iat II DfOM 10-EPDE-314-RTS		44,035		-		-		-		-	
6	421	421027	MO Iat II Amrt OM ER-2011-0004		77,583		78,925		57,796		67,158		67,584	-
7	421	421029	MO PlmPt Amrt O&M ER-2011-0004		1,281		1,254		1,324		1,289		1,305	-
8			**Total Iatan/Plum Pt Deferred Operating Expenses:**		201,573		115,870		90,231		101,819		102,476	-
9			**Operation Supervision and Engineering Expenses:**											
10	500	500011	Conv & Seminar-Operations	#	14,795	@	2,937	%	48,093	^	10,739	*	77,124	3,650
11	500	500035	Professional Assc Dues-Prod		367		1,835		1,235		865		371	18
12	500	500036	Opr Spr & Eng-Air Abate&Monit		298,212		231,124		293,481		326,163		255,430	12,087
13	500	500037	Op Supv-Water Monit & Compliance		-		-		683		1,541,572		11,574	548
14	500	500038	Op Supv-Solid Wste Monit&Compl		-		-		150		4,076		150	7
15	500	500039	Operation Supervision & Eng		1,601,577		1,515,200		1,642,789		5,621		1,704,088	80,637
16	500	500046	Micro Software-Production		6,044		2,641		3,176		450,989		750	35
17	500	500180	Regulatory & Environm Report		6,493		5,621		10,903		(500,666)		10,903	516
18	500	500994	IatanII Op Rg Adj Amortization		(93,746)		415,385		(32,737)		(120,299)		(32,737)	-
19	500	500995	IatCom Op Reg Adj Amortization		538,755		(418,129)		126,513		-		126,513	-
20	500	500996	PP Op Trk Reg Adj Amortization		(37,146)		(182,880)		18,385		-		18,385	-
21	500	500997	IatanII Opr Rg Adj ER2011-0004		46,844		-		-		-		-	-
22	500	500998	IatCom Opr Reg Adj ER2011-0004		(133,085)		-		-		-		-	-
23	500	500999	PP Op Trk Reg Adj ER-2011-0004		748,135		-		-		-		-	-
24	500		**Total Operation Supervision and Engineering Expenses:**		2,997,246		1,573,733		2,112,671		1,719,059		2,172,551	97,497
25			**Fuel Expenses (Steam Generation):**											
26	501	501001	Kansas Fuel Adj	#	822,575	@	(21,201)	%	(484,917)	^	184,793	*	(1,213,153)	(1,213,153)
27	501	501002	MO Fuel Adj Current Period		6,868,941		7,860,621		(13,592,323)		(3,966,411)		(14,467,448)	-
28	501	501003	MO Fuel Adj Recovery		1,391,142		(8,099,107)		(4,359,682)		(12,546,587)		8,509,737	-
29	501	501004	Fuel Constr Acctg Iatan2 Def		(158,466)		(155,535)		(117,224)		(136,212)		(138,468)	-
30	501	501005	Okla Fuel Cost Adj		(72,196)		58,560		63,024		44,478		61,195	-
31	501	501011	Conv & Seminar-Fuel		1,938		995		-		995		-	-
32	501	501042	Fuel - Coal		48,449,359		47,397,912		47,163,362		46,349,555		45,681,569	2,059,402
33	501	501045	Fuel - Oil		1,016,917		556,518		751,700		539,542		1,020,499	46,006
34	501	501054	Fuel - Natural Gas		2,332		-		-		-		-	-
35	501	501182	Ash Handling Expense		2,422		-		-		-		-	-
36	501	501183	Sales Of Ash		(75,017)		(66,123)		(75,980)		(71,906)		(66,454)	(2,996)
37	501	501300	Fuel - Tires		75,406		63,019		53,205		45,060		50,977	2,298
38	501	501400	Ops Labor-Fuel Handling		140,324		140,950		148,540		198,289		135,560	6,111
39	501	501401	Ops Mtls-Fuel Handling		134,928		203,374		219,720		189,238		177,446	8,000
40	501	501601	Fuel Administration - Asbury		101,349		86,498		49,571		72,342		40,191	1,812
41	501	501604	Fuel Administration - Riverton		(47)		-		695		237		814	37
42	501	501605	Fuel Administration Plum Point		141,636		117,224		104,209		109,696		105,503	4,756
43	501	501910	Amrt SWPA Oz Beach-AR		(14,654)		(14,654)		(14,654)		(14,654)		(14,654)	-
44	501	501920	Amrt SWPA Oz Beach-KS		(125,260)		(125,260)		(125,260)		(125,260)		(125,260)	(125,260)
45	501	501930	Amrt SWPA Oz Beach-MO		(2,307,277)		(2,315,427)		(2,054,822)		(2,212,005)		(2,189,483)	-
46	501	501940	Amrt SWPA Oz Beach-OK		(69,006)		(69,036)		(69,036)		(69,036)		(69,036)	-
47			**Total Fuel Expenses (Steam Generation):**		56,327,345		45,619,328		27,660,128		28,592,153		37,499,534	787,013
48			**Steam Expenses:**											
49	502	502084	Exp Of Coal Handling System	#	2,894	@	6,982	%	4,226	^	6,953	*	3,593	162
50	502	502093	Exp Of Feedwater System		117,405		51,304		44,452		38,059		42,653	1,923
51	502	502096	Exp To H2O Supply System		86,888		82,570		65,451		72,179		76,881	3,466
52	502	502099	Exp Of Bottom & Fly Ash System		18,183		40,062		40,717		47,613		27,072	1,220
53	502	502102	Exp Of Instrmnt & Meter Boiler		124,743		173,006		133,867		165,349		91,038	4,104
54	502	502103	Expense of CEMS Equipment		-		-		5,938		-		32,237	1,453

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
55	502	502105	Exp Of Draft Equipment		152		749		598		1,024		655	30
56	502	502108	Exp Of Steam Boiler		1,128,428		1,046,457		867,840		1,086,744		412,138	18,580
57	502	502109	Boiler Ops & Supervision		213,142		191,925		196,055		256,820		185,221	8,350
58	502	502114	Steam Expenses - Other		2,136,262		1,659,267		1,375,888		1,534,833		1,359,000	61,266
59	502	502168	Sel Catalytic Reduction - Ops		43		40		-		-		-	-
60			**Total Steam Expenses:**		3,828,140		3,252,361		2,735,031		3,209,574		2,230,488	100,554
61			**Electric Expenses:**											
62	505	505112	Exp-Condens & Cooling H2O Sys	#	153,814	@	232,623	%	413,368	^	228,753	*	586,242	27,741
63	505	505117	Exp Of Lube Oil System		3,756		7,609		1,909		3,920		14,614	692
64	505	505118	Expense of Generator		-		-		6,657		-		21,553	1,020
65	505	505119	Exp Of H2 System		7,395		-		-		-		-	-
66	505	505120	Exp Of Turbine Plant		462,499		144,559		306,697		126,568		483,521	22,880
67	505	505422	Electric Expense - Iatan		368,295		382,979		392,635		393,386		376,819	17,831
68	505	505426	Electric Ops & Supervision		161,988		163,723		168,226		228,253		156,084	7,386
69			**Total Electric Expenses:**		1,157,746		931,493		1,289,493		980,881		1,638,832	77,549
70			**Miscellaneous Steam Power Expenses:**											
71	506	506025	Safety Expenses-Prod	#	76,689	@	133,691	%	132,091	^	163,941	*	75,233	3,560
72	506	506126	Misc Steam Power Expenses		1,317,448		912,026		1,104,013		1,010,310		1,121,766	53,082
73	506	506128	Powdered Activated Carbon		-		8		-		8		-	-
74	506	506168	Exp of Catalytic Reducer - Opr		37,307		67,819		50,008		59,547		39,210	1,855
75	506	506173	Exp of Scrubber		7,492		6,781		15,587		1,580		15,587	738
76	506	506175	Exp of Baghouse		52,330		44,675		15,504		51,848		360	17
77	506	506176	Exp of Hydrator		120		1,810		1,953		3,763		-	-
78	506	506201	Limestone Expense		761,615		1,026,443		834,448		961,318		799,648	37,839
79	506	506202	Ammonia Expense		870,663		664,655		542,098		578,024		506,654	23,975
80	506	506203	Powdered Activated Carbon		135,356		170,024		134,751		173,133		113,821	5,386
81	506	506204	Lime Expense		254,255		224,270		211,047		223,482		259,559	12,282
82	506	506205	Ash and FGD By product Disposa		120,095		106,954		149,135		121,160		151,492	7,169
83	509	509052	Emission Allowance Exp		750		-		-		-		-	-
84			**Total Miscellaneous Steam Power Expenses:**		3,634,119		3,359,156		3,190,633		3,348,112		3,083,330	145,903
85			**Rents:**											
86	507	507129	Rents - Energy Supply	#	2,111	@	47,882	%	55,185	^	47,892	*	65,605	3,104
87			**Total Rents:**		2,111		47,882		55,185		47,892		65,605	3,104
88			**Operation Supervision and Engineering Expenses:**											
89	535	535011	Conv & Seminar-Hydro	#	4,947	@	4,172	%	300	^	4,472	*	2,520	119
90	535	535301	Oper Supervision & Eng-Hydro		27,237		425		57,557		45,638		40,422	1,913
91			**Total Operation Supervision and Engineering Expenses:**		32,185		4,597		57,857		50,110		42,942	2,032
92			**Hydraulic Expenses:**											
93	537	537316	Other Expenses - Hydro	#	6,170	@	7,041	%	20,705	^	20,972	*	31,552	1,493
94			**Total Hydraulic Expenses:**		6,170		7,041		20,705		20,972		31,552	1,493
95			**Electric Expenses:**											
96	538	538325	Electric Expenses - Hydro	#	42,853	@	30,629	%	31,221	^	24,795	*	56,824	2,689
97			**Total Electric Expenses:**		42,853		30,629		31,221		24,795		56,824	2,689
98			**Miscellaneous Hydraulic Power Generation Expenses:**											
99	539	539025	Safety Expenses-Hydro	#	1,604	@	5,482	%	22,687	^	8,366	*	29,329	1,388
100	539	539332	Misc Hydro Generation Exp		355,292		194,878		202,278		197,879		234,170	11,081
101			**Total Miscellaneous Hydraulic Power Generation Expenses:**		356,895		200,360		224,965		206,244		263,499	12,469
102			**Operation Supervision and Engineering Expenses:**											
103	546	546011	Conv & Seminars	#		@	4,305	%	2,509	^	1,922	*	2,167	103
104	546	546204	Oper Super&Eng-Air Abate&Monit		22,030		30,241		53,276		45,638		66,638	3,153

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
105	546	546205	Op Supv - Environmental		14,128		38,007		41,155		51,300		31,908	1,510
106	546	546207	Oper Supervision & Eng		416,005		606,590		745,343		714,345		790,204	37,392
107			**Total Operation Supervision and Engineering Expenses:**		452,163		679,143		842,283		813,205		890,918	42,158
108			**Fuel Expenses (Other Generation):**											
109	547	547208	Comb Turb Fuel Sales - Nat Gas	#	-	@	(55,650)	%	-	^	(55,650)	*	-	-
110	547	547210	Combust Turb Fuel Natural Gas		37,857,115		48,143,099		69,020,837		61,544,496		68,405,519	3,083,836
111	547	547213	Fuel - No 2 Oil Fuel		711,644		30,618		264,144		211,378		2,968,727	133,835
112	547	547300	MO/KS Deriv Unrecov Fuel Exp		(162,438)		(965,105)		423,001		(4,265)		(99,278)	(5,146)
113	547	547301	NonFAS133 Deriv (Gain)/Loss		7,993,467		3,659,557		1,225,752		1,387,425		2,052,930	92,550
114	547	547603	Fuel Adm Riverton Gas		-		-		812		-		812	37
115	547	547605	Fuel Adm State Line		676		2,148		1,739		1,652		936	42
116	547	547606	Fuel Adm Energy Center		790		2,148		1,333		1,652		530	24
117	547	547607	Fuel Adm E Traders Commission		29,729		32,035		31,014		45,978		22,816	1,029
118			**Total Fuel Expenses (Other Generation):**		46,430,984		50,848,849		70,968,633		63,132,665		73,352,992	3,306,206
119			**Generation Expenses:**											
120	548	548123	Exp Of Prime Movers	#	1,205,502	@	2,100,376	%	2,684,266	^	2,479,618	*	2,890,853	136,795
121	548	548124	Exp of Environmental Devices		128,813		125,447		191,198		180,953		157,826	7,468
122	548	548125	Exp of Generators		29,308		33,411		36,428		41,723		36,424	1,724
123	548	548126	Exp of Accessory Elec Equip		26,244		28,015		28,907		32,424		29,373	1,390
124	548	548202	Ammonia Expense		169,783		205,132		199,494		209,041		246,547	11,667
125	548	548216	Gener Exp - Water Injection Sys						11,876				12,135	574
126	548	548219	Generation Expense - Other		387,666		512,041		468,880		483,591		441,960	20,913
127			**Total Generation Expenses:**		1,947,317		3,004,422		3,621,047		3,427,349		3,815,118	180,531
128			**Misc. Other Power Generation Expenses:**											
129	549	549025	Safety Expenses-Comb Turbine	#	7,516	@	108,845	%	43,201	^	102,285	*	68,351	3,234
130	549	549046	Micro Software - Comb Turbine		393		4,387		483		4,387		483	23
131	549	549120	Exp of Misc Other Power		453,645		896,566		1,311,887		1,239,938		1,199,030	56,738
132	549	549169	Riverton OprTrk MO ER2016-0023		-		(159,167)		(351,102)		(334,234)		(360,638)	-
133	549	549222	Misc Other Power Expense		155,277		173,566		172,715		164,955		160,835	7,611
134			**Total Misc. Other Power Generation Expenses:**		616,830		1,024,197		1,177,183		1,177,332		1,068,061	67,606
135			**On-System Purchase Power (Energy):**											
136	555	555430	Direct Purchases	#	35,816,609	@	38,029,305	%	38,719,099	^	38,645,504	*	39,031,723	1,759,616
137	555	555700	TCR Unreal/Unrecov		108,489		53,127		(5,109,924)		188,702		-	-
138	555	555800	DA Asset Energy Purchase		23,273,107		12,064,781		6,214,747		10,232,960		11,763,008	530,296
139	555	555810	DA NonAsset Energy Purchase		399,853		-		-		-		-	-
140	555	555820	DA Virtual Energy Purchase		1,374,411		639,295		852,157		942,585		3,027,547	136,487
141	555	555840	DA Reg Up Cost		187,852		207,017		216,840		227,642		275,095	12,402
142	555	555850	DA Reg Down Cost		180,493		74,337		75,685		81,099		88,715	3,999
143	555	555860	DA Spin Reserve Cost		181,576		208,272		290,675		258,375		356,207	16,058
144	555	555870	DA Supp Reserve Cost		118,760		85,644		82,207		80,910		81,894	3,692
145	555	555880	DA Other PP Expense		(950,839)		654,903		739,710		678,719		224,906	10,139
146	555	555900	RT Asset Energy Purchase		3,960,268		4,086,690		6,335,577		5,869,389		8,334,816	375,748
147	555	555910	RT NonAsset Energy Purchase		11,840		5,179		-		184		-	-
148	555	555920	RT Virtual Energy Purchase		403,585		508,868		558,527		566,704		712,187	32,107
149	555	555940	RT Reg Up Cost		373,825		257,045		488,461		378,717		364,667	16,440
150	555	555950	RT Reg Down Cost		315,443		344,650		923,007		617,705		700,612	31,585
151	555	555960	RT Spin Reserve Cost		118,782		177,943		275,100		253,225		159,999	7,213
152	555	555970	RT Supp Reserve Cost		8,795		3,451		6,500		6,384		5,073	229
153	555	555980	RT Other PP Expense		(1,127,912)		(1,622,716)		(815,012)		(1,134,616)		(1,238,285)	(55,824)
154	555	555990	TCR Settlements		869,791		(5,028,973)		(19,017,256)		(11,913,307)		(17,574,482)	(792,287)
155	555	555995	Auction Revenue Rights		(7,120,808)		(3,296,926)		(5,942,504)		(4,551,952)		(9,428,198)	(425,039)
156			**Total On-System Purchase Power (Energy):**		58,503,921		47,451,892		24,893,646		41,428,930		36,885,485	1,662,860
157			**On-System Purchased Power (Demand)**											

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
158	555		Resource Capacity	(A)	8,597,729	(A)	10,509,544	(A)	10,735,303	(A)	10,448,074	(A)	10,995,421	520,301
159			**Total On-System Purchased Power (Demand)**		8,597,729		10,509,544		10,735,303		10,448,074		10,995,421	520,301
160			**System Control and Load Dispatching Expenses:**											
161	556	556001	Mgmt & Admin- Trans Operations	#	34,045	@	31,192	%	25,709	^	28,395	*	24,479	1,158
162	556	556012	Sys Control/Load Disp Training		31,755		41,411		51,879		48,905		104,172	4,929
163	556	556023	Building Operations-Sys Cntrl		52,421		78,038		88,743		84,829		83,079	3,931
164	556	556025	Safety Exp		9,412		9,416		7,600		6,951		6,524	309
165	556	556201	Janitorial Exp-System Ops		11,274		14,981		14,880		14,990		13,860	656
166	556	556205	Utilities - System Operations		1,422		931		911		921		2,060	97
167	556	556401	Sys Control & Generation Disp		394,726		378,514		388,691		388,521		375,634	17,775
168	556	556410	EMS System Maintenance		185,053		204,816		210,419		211,453		226,645	10,725
169	556	556411	Computer Operations		7,742		332		390		390		207	10
170	556	556415	REC Fees & Commissions		51,633		65,642		19,696		35,924		22,575	1,068
171	556	556412	Energy Trading		1,048,611		1,007,177		619,997		632,949		760,147	35,970
172	556	556413	Energy Accounting		478,870		473,561		526,238		533,232		718,570	34,003
173	556	556508	Telmetering/Load Control				532				11		-	-
174	556	556523	Other Fiber Utility		1,379,352		1,379,352		1,379,352		1,379,352		1,379,352	65,271
175			**Total System Control and Load Dispatching Expenses:**		3,686,316		3,685,894		3,334,504		3,366,822		3,717,304	175,902
176			**Other Expenses:**											
177	557	557410	Pool Operation	#	381,126	@	282,583	%	297,734	^	289,739	*	306,254	14,492
178	557	557448	Other Pwr Supply Expense		299,101		290,092		214,732		261,330		178,380	8,441
179			**Total Other Expenses:**		680,227		572,675		512,466		551,069		484,635	22,933
180			**Transmission Operation Expenses:**											
181	560	560011	Conv & Seminar-Transm Op	#	106,536	@	106,007	%	94,512	^	81,894	*	95,930	4,539
182	560	560025	Safety Expenses-Line Eng		1,021		410		528		274		770	36
183	560	560046	Computer Software-Engineer		42,145		23,331		40,611		35,985		22,640	1,071
184	560	560449	Transm Operation Super & Engr		-		311		-		295		54	3
185	560	560490	Computer Programming		5		444		-		444		-	-
186	560	560628	T & D Eng-Oper Supervision		97,983		117,586		105,701		101,666		95,551	4,521
187	560	560629	Transmission System Planning		244,135		200,184		193,285		201,445		206,834	9,787
188	561	561012	Load Dispatching Training		332		-		247		71		176	8
189	561	561404	Transm System Operations		497,545		514,222		606,114		566,232		588,929	27,868
190	561	561450	Transm Oper-Load Dispatching		1,482		1,427		1,301		1,239		1,196	57
191	561	561501	NERC - Facilities Rating		502		-						-	-
192	561	561505	Power Line Carrier Expenses		30,291		16,450		27,322		21,736		17,930	848
193	562	562010	Transm Substation Operations		130,946		150,918		210,035		195,871		172,294	8,153
194	562	562111	Exp of Substation & Switchyard		2,788		2,570		3,528		3,080		2,980	141
195	562	562121	Substation Expenses		4,269		4,022		3,451		3,221		4,195	198
196	562	562134	Mtce Of Substation Switchyard		238,183		270,765		279,305		276,815		303,925	14,382
197	562	562452	Transmission Station Expenses				49				49		-	-
198	563	563011	Overhead Trans Line Oper-161Kv		1,965		23,065		5,436		27,693		842	40
199	563	563012	Overhead Trans Line Oper-69 Kv		93,747		48,959		34,650		45,666		28,360	1,342
200	563	563014	Overhead Trans Ln Oper-34.5 Kv		2,608		2,043		2,632		1,166		8,012	379
201	563	563015	Overhead Trans Line Oper-Other		2,187		2,839		4,657		1,359		4,418	209
202	565	565413	Trans Of Electricity By Others		1,292		-				-		-	-
203	565	565414	SPP Fixed Chg - Native Load		12,871,634		13,809,874		14,640,246		14,784,208		15,254,484	762,436
204	565	565415	SPP Var Chg - Native Load		377,579		337,779		314,070		330,563		364,041	17,226
205	565	565416	Non SPP Fixed Chg -Native Load		4,470,037		2,465,047		3,936,506		2,479,720		4,125,213	195,204
206	566	566419	Off Sys Sales Trans Costs		136								-	-
207	566	566450	RTO/ISO Development		261,812		229,469		152,528		206,991		43,657	2,066
208	566	566458	Misc Transmission Expenses		22		967		123				68	3
209	566	566459	NERC Compliance/CIPS (706)		240,977		132,812		104,539		126,102		40,680	1,925
210	566	566462	NERC Compliance/EOP (693)		81,794		90,088		87,080		91,081		37,325	1,766
211	567	567007	Rents - Transmission		175		175		175		175		175	8
212			**Total Transmission Operation Expenses:**		19,804,127		18,551,814		20,848,581		19,585,041		21,420,679	1,054,219

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
213			**Distribution Operation Expenses:**											
214	580	580001	Supervision Distribution Oper	#	486,164	@	599,981	%	830,094	^	714,416	*	820,465	45,118
215	580	580002	System Perform Mgmt & Admin		63,779		61,031		9,506		35,419		6,782	373
216	580	580011	Conv & Seminar-Distrib Op		63,142		65,122		48,540		56,185		52,905	2,909
217	580	580016	Engineering Recruiting Exp		2,569		2,203		13,017		9,707		4,973	273
218	580	580046	Software - Transf Superviser		-		117		460		460		1,000	55
219	580	580627	Line Eng - Distrib Operations		167,539		170,307		169,214		168,715		185,844	10,220
220	580	580628	Distribution System Planning		135,320		123,475		93,023		109,325		87,073	4,788
221	580	580686	Maintain Construction Standard		69,492		68,669		53,998		75,920		49,484	2,721
222	580	580690	AVL Mobile Operations		48,587		58,228		44,077		46,860		36,915	2,030
223	582	582016	Distribution Substa Operations		209,364		226,590		203,644		228,066		207,549	11,413
224	583	583019	Oh Distribution Line Oper		1,594,255		1,538,909		1,059,188		1,417,785		1,077,843	59,271
225	583	583020	Truck Down Time - Line Oper		65,821		106,724		122,892		98,280		118,680	6,526
226	583	583021	Truck Traveling Time - Line Op		22,494		29,827		2,218		15,735		3,896	214
227	583	583025	Safety Exp-Oh Distrib Lines		29,253		16,997		18,208		15,955		26,397	1,452
228	583	583172	Electric Testing-Oh Dis Lines		79,118		72,774		75,872		85,897		63,506	3,492
229	583	583500	Training Dist Operations-Ovhd		55,450		34,108		21,151		34,458		14,736	810
230	583	583501	Distr OH Training Stipend		3,192		604		1,677		297		2,315	127
231	584	584022	Underground Distrib Line Oper		503,355		822,805		543,175		719,372		320,856	17,644
232	584	584025	URG Dist Line Locates		287,521		48,893		372,222		145,299		517,998	28,485
233	585	585025	Street Lightg & Signal Sys Exp		70,285		81,555		43,759		70,799		41,661	2,291
234	586	586025	Safety Expenses-Meters		5,909		1,946		2,399		1,671		5,265	290
235	586	586028	Meter Expense		1,776,125		1,678,366		1,395,889		1,547,516		1,297,834	71,369
236	586	586029	Disconnects & Reconnects		742,760		830,245		1,165,143		982,746		1,193,932	65,655
237	586	586120	Field Testing - Old		428,338		335,319		263,067		303,953		262,605	14,441
238	586	586135	Load Research-Meters		56,721		71,456		161,412		79,026		183,681	10,101
239	586	586140	Power Quality Investiagtions		25,545		18,004		19,989		21,867		13,203	726
240	586	586150	AMR Fixed Network - Meters		191		1,629		71		1,637		52	3
241	586	586155	AMR Radio - Meters		72,741		63,973		39,621		51,882		31,518	1,733
242	587	587031	Service Call Expense		62,076		59,760		75,420		75,789		102,191	5,620
243	587	587038	Customer Facilities Expense		71,021		34,482		63,486		25,949		56,508	3,107
244	587	587126	Complaint Test		52,247		62,063		76,017		69,550		95,494	5,251
245	587	587146	Current Diversions		475		(367)		4,985		3,210		4,979	274
246	587	587147	Meter Base Repair		1,517		8,601		2,762		9,535		4,026	221
247	587	587148	Customer Co-Gen Facilities		(8,078)		(20,037)		(13,987)		(12,081)		(18,871)	(1,038)
248	587	587519	Location-Radio & Tv Interfer		-		6,881		3,805		5,499		1,296	71
249	588	588011	Conv & Seminar-Misc Distrib		90,805		77,343		62,303		61,784		78,389	4,311
250	588	588023	Building Operations - Expenses		741,012		572,804		493,268		488,855		492,147	27,063
251	588	588025	Safety Equipment		413,086		311,421		291,189		288,805		272,668	14,994
252	588	588046	Micro Software - Misc Dist		130		-						-	-
253	588	588100	Miscellaneous Distribution		26,007		382,344		287,774		389,521		308,981	16,991
254	588	588101	Janitorial Exp - Meter Shop		1,465		185		29				20	1
255	588	588105	Utilities - Meter Shop		1,503		1,443		817		1,176		724	40
256	588	588120	Misc Dist - Right-of-way		60,594		42,304		60,476		44,108		86,852	4,776
257	588	588130	Misc Dist. - Joint Use		75,777		71,545		75,481		75,842		71,943	3,956
258	588	588305	Utilities - MO Steel		12,492		9,175		2,967		8,701		-	-
259	588	588401	Janitorial Exp - Garage		8,907		4,554		865		869		590	32
260	588	588405	Utilities - Garage		858		863		845		784		810	45
261	588	588501	Janitorial Exp - 4Th & Rr		2,823		23		121		121		-	-
262	588	588505	Utilities - 4Th & Rr		774		843		204		698		-	-
263	588	588621	GIS Operations		173,638		195,462		75,921		142,838		62,469	3,435
264	588	588622	GIS Quality Assurance/Control		-		-		6,436		3,463		7,470	411
265	588	588623	GIS Analysis		-		-		21,170		6,418		33,163	1,824
266	588	588630	OMS Operations		96,608		108,957		119,847		119,866		115,693	6,362
267	589	589034	Rents - Distribution		2,272		2,531		2,766		3,486		2,302	127
268			**Total Distribution Operation Expenses:**		8,953,038		9,063,037		8,488,496		8,854,035		8,408,812	462,405

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
CUSTOMER ACCOUNT EXPENSES														
269	901	901001	Customer Service Mgmt & Admin	#	351,654	@	453,758	%	636,418	^	556,177	*	655,804	36,760
270	901	901002	Cust Ser Mgmt & Admin - Exp		20,133		21,248		17,045		19,273		16,166	906
271	901	901011	Conv & Seminar-Cust Accts Dist		11,254		20,929		13,470		20,162		12,557	704
272	901	901025	Safety Exp-Customer Service		748		707		705		876		397	22
273	901	901042	Outside Printing-Customer Serv		8,050		10,195		8,825		9,017		7,939	445
274	901	901201	Mgmt & Administrative - Accoun		78,138		68,916		75,862		68,526		81,164	4,550
275	902	902005	Check Meter Reads - Electric		8,118		15,074		33,048		20,097		57,273	3,210
276	902	902007	Read Meters - Electric		1,929,666		1,972,860		2,011,037		1,990,343		1,982,726	111,138
277	903	903002	Collection Activities - Gas						675				1,422	80
278	903	903013	Power Billing		5,996		3,816		4,716		2,739		5,362	301
279	903	903016	Collection Activities - Elec		273,328		219,768		182,275		180,522		153,922	8,628
280	903	903022	Cust Serv Accounting - Ele/Gas		1,848,270		1,710,676		1,692,356		1,698,647		1,757,977	98,540
281	903	903023	Remittance Processing		114,738		82,266		114,040		84,576		139,279	7,807
282	903	903028	Credit & Collections		234,476		200,904		163,830		164,844		172,675	9,679
283	903	903046	Micro Software-Rev Acct		3		718		588		686		361	20
284	903	903110	Billing Of Metered Accts-Elec		1,253,871		1,251,489		1,190,936		1,204,114		1,199,574	67,240
285	903	903146	Collectors' Fees		119,062		136,573		140,377		143,609		132,391	7,421
286	903	903148	Banking Fees - Mercantile		6,057		5,254		5,900		5,611		6,430	360
287	903	903150	Rating Agency Fees		229,898		196,977		149,860		192,640		146,034	8,186
288	903	903151	Banking Fees - UMB		145,193		116,676		116,039		117,581		116,381	6,524
289	904	904037	Uncollectible Accts-Electric		1,791,218		1,400,395		1,664,572		1,566,793		1,984,992	111,265
290	904	904038	Uncollect - Misc Receivables		311		-						-	-
291	905	905023	Building Operations-Cust Accts		105,102		82,894		74,791		82,415		88,028	4,934
292	905	905031	General Office Exp-Cust Acct		5,281		6,108		10,738		7,107		9,062	508
293	905	905032	Phone Directory Expense		14,455		19,235		17,667		16,013		16,357	917
294	905	905042	Outages		716		483		1,569		1,673		55	3
295	905	905045	Cyber Insurance		68,551		63,714		26,416		51,039		9,993	560
296			**Total Customer Account Expenses:**		**8,624,288**		**8,061,632**		**8,353,756**		**8,205,081**		**8,754,321**	**490,707**
CUSTOMER ASSISTANCE EXPENSES														
297	907	907101	Customer Service Supervision	#	160,529	@	136,054	%	204,534	^	188,751	*	207,128	11,610
298	908	908011	Out-Of-Area Convention/Seminar		-		289						-	-
299	908	908043	Customer Assistance-Cust Serv		178,693		127,575		153,968		134,955		149,539	8,382
300	908	908046	Micro Software-Mjr Accts		-		672		920		195		920	52
301	908	908101	Retail Indust Cust Assistance		378,993		395,087		398,833		407,154		423,504	23,739
302	908	908103	Cust Prog Collaborative Exp		1,043,182		1,313,708		1,587,160		1,449,974		1,612,408	-
303	908	908104	Wholesale Customer Assistance		33,447		41,102		73,102		39,570		114,690	-
304	908	908106	Retail Commercial Cust Assist		547,594		525,619		451,012		532,509		449,236	25,182
305	908	908107	Retail Residential Cust Assist		253,430		243,904		208,402		248,098		198,109	11,105
306	908	908108	Low Income Weatherization Prgm		(375)		-						368	21
307	908	908113	DSM Implementation		257		-						-	-
308	908	908114	Net Metering/Cogen Activities		69,953		(168)						-	-
309	908	908116	MO Low Inc Weather ER2014-0351		94,855		140,961		188,198		109,204		203,994	-
310	908	908117	Solar Rebate Amrt ER-2016-0023		-		180,849		620,055		490,876		620,055	-
311	908	908120	Energy Efficiency Cost Recover		22,754		56,453		12,319		38,239		36,707	-
312	908	908123	KS En Eff 10-EPDE-497-TAR		8,936		5,003				5,003		-	-
313	908	908124	Dem Side Mgmt Rider OK		-		5,010		99		5,010		99	-
314	909	909116	E.D. Advertising		106		2,000		2,490		2,495		1,994	112
315	909	909231	Info & Instruct Ad - Radio		52,942		53,745		26,544		34,096		20,291	1,137
316	909	909232	Info & Instruct Ad - Tv		75,393		84,104		45,498		54,141		36,322	2,036
317	909	909233	Info & Instruct Ad - Newsppr		48,552		40,271		39,277		34,591		43,752	2,452
318	909	909235	Info & Instruct Ad-Schl Pub		200		-		-		-		-	-
319	909	909236	Info & Instruct Ad - Other		4,063		8,020		3,575		7,820		7,600	426
320	909	909316	Other Promotion		-		-		4,394		4,394		-	-
321	910	910008	Cust Serv & Public Info-Cler		12,524		11,034		15,428		12,760		17,440	978
322			**Total Customer Assistance Expenses:**		**2,986,029**		**3,371,292**		**4,035,808**		**3,799,833**		**4,144,157**	**87,232**

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
SALES EXPENSE														
323	912	912002	Municipal Activities	#	13,465	@	7,847	%	13,246	^	7,804	*	12,760	548
324	912	912011	Conferences		13,122		10,388		7,068		9,539		3,437	148
325	912	912025	New Business-Cust Serv		158,232		126,623		127,427		131,311		127,182	5,465
326	912	912113	Ed Admin-Labor Veh & Other		9,863		8,815		10,340		5,696		10,340	444
327	912	916046	Micro Software-Sales		-		101				(18)		-	-
328			**Total Sales Expenses:**		**194,682**		**153,774**		**158,081**		**154,331**		**153,719**	**6,605**
RESEARCH AND DEVELOPMENT														
329	930	930232	**Total Research and Development:**	#	-	@	-	%	-	^	-	*	-	-
OTHER ADMINISTRATIVE AND GENERAL EXPENSES														
330	920	920101	Mgmt & Admin - Executives	#	2,564,365	@	3,151,443	%	833,291	^	2,305,821	*	486,175	20,610
331	920	920102	Mgmt Incentive - LTIP		-		-		62,559				164,523	6,974
332	920	920103	Executive Performance Shares		929,141		2,183,137				1,536,706		-	-
333	920	920104	Restricted Stock Awards		328,710		741,204				209,681		-	-
334	920	920109	Mgmt & Adm Salaries-Spec Proj		-		-		10,824		4,967		(5,884)	(249)
335	920	920112	LUC Labor Allocs		-		-		377,636		201,325		486,967	20,643
336	920	920130	M&A Transf Work Gas-GL001 Only		-		-		(354)				(354)	(15)
337	920	920201	Mgmt & Admin - Salaries-Acct		494,216		591,151		418,525		527,109		388,160	16,455
338	920	920212	APUC Labor Allocs		-		-		1,655,469		629,252		1,616,404	68,522
339	920	920261	General Recordsaccounting		483,649		537,058		581,939		536,416		626,391	26,554
340	920	920264	Accounts Payable-Accounting		143,243		153,469		168,472		162,433		167,578	7,104
341	920	920301	Mgmt & Admin - Field Safety Ad		507,534		526,095		559,734		527,609		519,382	22,017
342	920	920312	LUSC BS Labor Allocs		-		-		-		-		143,747	6,094
343	920	920412	LABS CAN BS Labor Allocs		-		-		886,264		337,342		1,483,326	62,880
344	920	920413	LABS BS Labor Allocs-Electric		-		-		-		-		99,619	4,223
345	920	920449	Mgmt & Admini - Salaries-Info		792,427		757,407		44,140		430,620		(19,737)	(837)
346	920	920450	Personnel - Salary - Info Serv		1,829,792		1,863,010		423,122		1,386,802		(28,877)	(1,224)
347	920	920455	Personnel - Hourly - Info Serv		-		1,570		4,741		4,741		-	-
348	920	920501	Mgmt & Admini - Salaries-Hr		248,232		263,095		97,277		217,652		(18,080)	(766)
349	920	920503	Payroll Activi-Labor Only-Hr		143,862		155,219		115,816		138,635		46,417	1,968
350	920	920504	Personnel Activi-Lbr Only-Hr		221,450		241,053		142,507		211,285		103,115	4,371
351	920	920505	Train Program Dev - Labor-Hr		65,628		67,635		63,552		68,717		23,484	996
352	920	920512	LABS CAN CS Labor Allocs		-		-		1,795,983		378,842		2,200,187	93,269
353	920	920513	LABS CS Labor Allocs-Electric		-		-		-		-		130,397	5,528
354	920	920601	Mgmt & Admin-General Services		139,285		137,982		246,392		227,157		173,807	7,368
355	920	920612	LABS US BS Labor Allocs		-		-		2,895		911		1,984	84
356	920	920615	Purchasing Activities-Gen Serv		79,636		128,424		143,472		140,288		142,229	6,029
357	920	920623	Janitorial Serv-Labor-Gen Serv		15,436								-	-
358	920	920666	Receive & Deliver Company Mail		18,993		19,961		20,324		20,339		18,086	767
359	920	920669	General Service Activities		60,055		57,791		46,150		53,858		44,096	1,869
360	920	920701	Mgmt & Admin-Sal-Other Gen Off		1,627,319		1,515,503		572,745		1,197,778		275,733	11,689
361	920	920703	Reporting Activities - Gen Off		546,451		469,451		383,257		447,741		345,429	14,643
362	920	920715	LABS US CS Labor Allocs		-		-		14,157		554		13,603	577
363	920	920721	Load Research		100,378		108,838		85,465		109,462		38,856	1,647
364	920	920750	Mgmt & Admin - Land Rights		79,578		77,088		129,045		90,599		137,008	5,808
365	920	920799	Transfer Acct for BU Errors		-		-		(2)		(0)		(2)	(0)
366	920	920812	CENTRAL Labor Allocs		-		-		158,078		41,691		204,308	8,661
367	920	920813	Central OC Labor Allocs-Electr		-		-		-		-		113,752	4,822
368	920	920881	MO Renewable Energy Std Labor		196,727		291,056		127,532		147,299		118,736	-
369	920	920882	Administrative & General Sal		77,908		142,413		82,801		121,921		52,540	2,227
370	920	920883	KS Renewable Energy Std Labor		-		750		3,616		1,515		4,964	4,964
371	920	920912	LIB CORP US Labor Allocs		-		-		2,688		2,688		108,435	4,597
372	921	921050	Ap Vendor Discount		-		(2,625)		(3,727)		(6,353)		-	-
373	921	921102	Mgmt & Admin-Exp-Executives		234,561		203,747		116,160		159,448		76,916	3,261
374	921	921103	SPP Administrative Expenses		5,517		10,126		4,356		7,016		4,099	174
375	921	921104	United Way Expenses		13,763		9,074		(4,576)		9,074		7,491	318

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
376	921	921105	Employee Engagement Program		-		-		648				648	27
377	921	921111	M&A Expenses - Util Planning		-		-		10,898		1,906		28,613	1,213
378	921	921112	LUC Other Allocs	#	-	@	-	%	86,995	^	85,615	*	48,227	2,044
379	921	921202	Mgmt & Admin-Accounting		51,619		162,087		45,863		167,539		50,979	2,161
380	921	921211	Conv & Seminar-Acct		19,138		41,588		14,391		33,004		5,001	212
381	921	921212	APUC CS Other Allocs		-		-		32,459		32,459		-	-
382	921	921225	Safety Expenses-Accounting		1,251		705		2,349		2,202		1,294	55
383	921	921246	Micro Software-Acct		47,167		27,788		79,945		85,234		34,496	1,462
384	921	921300	Pcb Oil & Used Oil		1,522		1,345		1,791		916		1,658	70
385	921	921301	Mgmt & Admin - Exp - Field Saf		44,580		35,832		165,759		133,971		91,127	3,863
386	921	921305	Required Certification Expense		981		574		811		587		1,201	51
387	921	921306	Professional Membership & Dues		2,818		3,412		3,093		2,764		2,120	90
388	921	921311	Conv & Seminars - Envir&Safety		4,306		5,684		1,837		3,667		3,674	156
389	921	921312	LUSC BS Other Allocs		5,718		9,228		9,412		8,304		92	4
390	921	921325	Misc Environmental Expenses										8,292	352
391	921	921402	Return Postage		139		43		23		22		320	14
392	921	921403	Offsite Expenses		7,153		9,629		2,418		7,743		1,426	60
393	921	921411	Conv & Seminar-Computer Serv		42,361		39,234		67,735		53,566		54,754	2,321
394	921	921412	LABS CAN BS Other Allocs		-		-		473,788		194,860		360,700	15,291
395	921	921413	LABS BS Other Allocs-Electric		-		-		-		-		1,351	57
396	921	921446	Micro Software-Info Serv		31,303		31,303		31,303		31,303		31,303	1,327
397	921	921449	Mgmt & Admin Exp - Info Serv		10,812		7,273		10,556		15,703		(3,927)	(166)
398	921	921450	Personnel Exp - Info Services		5,802		2,340		2,717		1,465		1,252	53
399	921	921469	Hardware Purchases		2,015		10,926		28,090		36,643		5,319	225
400	921	921470	Hardware Maintenance		267,474		291,935		168,423		346,657		37,980	1,610
401	921	921471	Software Purchases		125,540		36,146		36,454		19,234		32,512	1,378
402	921	921473	Data Processing Supplies		13,270		24,604		5,090		12,420		3,431	145
403	921	921474	Software Maintenance		1,070,713		1,230,843		1,209,316		1,439,722		851,138	36,081
404	921	921475	Telecommunications		21,411		27,528		20,316		24,028		17,169	728
405	921	921484	Manuals		67		59		65		133		(10)	(0)
406	921	921489	Supplies-Other		4,925		4,464		11,966		8,274		8,151	346
407	921	921502	Mgmt & Administrative - Exp-Hr		35,325		41,348		56,391		50,066		42,231	1,790
408	921	921506	Train Program Devel-No Lab-Hr		7,610		12,818		474		9,100		474	20
409	921	921511	Conv & Seminar-No Labor		2,047		896		633		100		633	27
410	921	921512	LABS CAN CS Other Allocs		-		-		606,731		127,554		705,391	29,903
411	921	921513	LABS CS Other Allocs-Electric		-		-		-		-		6,860	291
412	921	921516	Recruiting - No Labor-Hr		9,290		9,119		6,515		5,096		4,226	179
413	921	921602	Mgmt & Admin-Exp		36,748		37,164		36,487		38,272		29,265	1,241
414	921	921603	General Office Matrls & Sup		1,898		1,516		3,445		1,188		3,018	128
415	921	921611	Conv & Seminar-Gen Office		654		802		1,139		1,272		751	32
416	921	921612	LABS US BS Other Allocs		-		-		825				825	35
417	921	921620	Record Retention - Other		2,866		2,627		3,871		3,848		2,414	102
418	921	921625	Safety Exp-Bldg Serv		74,844		164		323		487		344	15
419	921	921639	Janitorial Service - Expenses		13,294		75,171		85,697		83,961		85,529	3,626
420	921	921648	Utilities		16,583		11,975		12,092		11,700		13,632	578
421	921	921654	Printing Expenses		24,987		17,667		21,449		17,215		19,776	838
422	921	921667	Rec & Del Company Mail - Exp		92,444		25,596		25,202		26,600		26,584	1,127
423	921	921702	Mgmt & Admin - Expenses		1,175		114,880		130,216		127,913		123,279	5,226
424	921	921703	Other General Office		20,592		710		185		224		309	13
425	921	921711	Conv & Seminar-Fras		2,488		22,980		11,594		22,344		6,374	270
426	921	921712	Education Expense		-		668		1,878		885		1,643	70
427	921	921715	LABS US CS Other Allocs		-		-		566		566		-	-
428	921	921717	Employee Clothing		801		(1,531)		(368)		(1,663)		(329)	(14)
429	921	921720	Fuel & PP Forecasting Exp		790		25,346		5,992		13,346		5,992	254
430	921	921721	Load Research Expenses		51,413		51,357				51,357		26,449	1,121
431	921	921722	Financial Projection Exp		10,648		11,817				11,817		-	-
432	921	921723	Forecasting - Other Expenses		-		-		5,691				5,691	241
433	921	921750	Mgmt & Admin - Exp Land Rights		17,562		15,643		19,964		12,143		22,573	957

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
434	921	921775	General Services Supplies		14,698		15,406		16,263		20,730		12,134	514
435	921	921776	Microcomputer Supplies		6,085		3,690		1,943		2,662		656	28
436	921	921812	CENTRAL Other Allocs		-		-		8,410		8,410		30,180	1,279
437	921	921881	Renewable Energy Std Veh Exp		21,622		38,693		25,003		25,877		29,514	1,251
438	921	921885	A&G Expenses Iatan		907,221		900,112		944,272		904,326		944,354	40,032
439	921	921886	Home Off Support Travel & Misc		6,108		-		12				25	1
440	921	921912	LIB CORP US Other Allocs		-		-		3,859		1,408		34,782	1,474
441	922	922000	Admin Exp Transf - Credit		(1,484,098)		(1,841,034)		(891,207)		(1,503,998)		(646,315)	(27,398)
442	922	922099	LABS US BS Reg Alloc Capitaliz		-		-		(106,274)		(106,274)		-	-
443	922	922101	Transfer charges- Subsidiaries		(1,160,046)		(1,114,291)		(1,381,767)		(1,227,556)		(1,336,591)	(56,660)
444	922	922185	Transfer Charges - WGI		(340,216)		(189,952)		(301,912)		(249,764)		(233,099)	(9,881)
445	922	922199	LUC CAN BS Alloc Capitalized		-		-		(725,529)		(372,737)		(682,398)	(28,928)
446	922	922299	APUC Corp CS Alloc Capitalized		-		-		(844,398)		(368,280)		(1,010,022)	(42,816)
447	922	922399	LUSC BS Alloc Capitalized		-		-		-		-		(30,206)	(1,280)
448	922	922499	LABS BS Capitalized		-		-		(282,420)		(111,824)		(383,993)	(16,278)
449	922	922500	Non-Prod Indirect Work - ELabs		-		-		5,798		9,089		5,005	212
450	922	922502	Services for LUC		-		-		-		-		-	-
451	922	922503	Services for Labs Canada		-		-		1,057		879		1,205	51
452	922	922504	Services for LUSC 8880		-		-		-		-		-	-
453	922	922505	Services for E-Labs (US) 8885		-		-				-		15,838	671
454	922	922506	Services for Labs (Labs US) GP		-		-		-		9,502		(9,502)	(403)
455	922	922507	Services for Liberty Corp US		-		-		-		240		(240)	(10)
456	922	922508	Services for APCO		-		-		4,415		11,339		(11,339)	(481)
457	922	922510	Services for Sanger Power 5519		-		-		35		5,506		(5,506)	(233)
458	922	922511	Services for Deerfield		-		-				312		(312)	(13)
459	922	922512	Services for O'Dell								3,963		(3,963)	(168)
460	922	922514	Services for Shady Oaks								960		(960)	(41)
461	922	922515	Services for St. Leon								2,191		(2,191)	(93)
462	922	922516	Services for Minonk		-		-				967		(967)	(41)
463	922	922517	Services for Senate		-		-		144		340		(340)	(14)
464	922	922599	LABS CAN CS Allocs Capitalized		-		-		(1,103,415)		(367,924)		(1,284,773)	(54,463)
465	922	922600	Services for East 8882		-		-		-		-		-	-
466	922	922601	Services for NH 8810		-		-				-		-	-
467	922	922604	Services for GA/Peach St 8862		-		-				-		-	-
468	922	922605	Services for N Eng/Mass 8866		-		-				-		-	-
469	922	922699	LABS US BS Capitalized		-		-		(606,690)		(306,441)		(654,650)	(27,752)
470	922	922700	Services for Central 8883		-		-		60,406		64,010		150,643	6,386
471	922	922701	Services for Empire Consol								1,621		20,410	865
472	922	922702	Services for Empire Elec 8905								1,399		(1,399)	(59)
473	922	922704	Services for Empire Fiber 8915								18		(18)	(1)
474	922	922705	Services for Pine Bluff 8606		-		-		-		9		168	7
475	922	922706	Services for WHall Water 8608		-		-		-		8		(8)	(0)
476	922	922708	Services for Mid States 8850	#	-	@	-	%	698	^	682	*	2,444	104
477	922	922709	Services for Mid States Water		-		-		5				2,009	85
478	922	922799	LABS US CS Capitalized		-		-		(15,918)		(13,963)		(1,986)	(84)
479	922	922800	Services for West 8884		-		-		1,093		-		1,317	56
480	922	922801	Services for Liberty Wtr 8020								-		47	2
481	922	922802	Services for Calpeco 8800		-		-		-		788		6,218	264
482	922	922803	Services for Park Water 8623										583	25
483	922	922899	Central Allocs Capitalized		-		-		(322,636)		(73,285)		(533,215)	(22,604)
484	922	922900	Indirect Liberty Corp US		-		-		969		6,361		(4,638)	(197)
485	922	922999	Liberty Corp US CS Capitalized		-		-		(85,461)		(27,550)		(161,564)	(6,849)
486	923	923010	LABS US BS Reg Indir Allocs		-		-		382,259		382,259		-	-
487	923	923045	Outside Services		1,511,838		1,600,166		403,891		975,666		1,338,080	56,723
488	923	923046	Outside Services - EDG Only		37,893		38,792		280		540		1,260	53
489	923	923047	Outside Services - EDE Only		1,148,467		460,010		442,005		402,656		589,552	24,992
490	923	923050	Management Fee		210,855		192,228		181,745		196,740		183,261	7,769
491	923	923051	O&M Fee - NAES		36,787		38,311		58,287		69,853		48,990	2,077

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
492	923	923110	LUC BS Indirect Allocs		-		-		3,100,672		1,598,401		2,714,319	115,064
493	923	923145	Outside Serv - Liab Claims		46,064		43,362		87,071		50,421		143,506	6,083
494	923	923154	Liab Claim Jason Hynes		(2,143)								-	-
495	923	923175	Liab Claims - PAR ELECTRIC		128,791								-	-
496	923	923177	Liab Claims - Shane Jackson		(60,823)		(17)						-	-
497	923	923181	Liab Claims-Class Action-Rider		45,242								-	-
498	923	923182	Liab Claims - Denker Asbestos		898		15,046		15,689		20,425		1,395	59
499	923	923210	APUC CS Indirect Allocs		-		-		2,323,353		1,082,344		2,682,974	113,735
500	923	923509	Outside Services - Training		44,121		6,713		9,058		11,799		11,688	495
501	923	923510	LABS CAN CS Indirect Allocs		-		-		2,789,547		1,183,523		3,212,387	136,178
502	923	923514	Outside Services - 401K Plan		1,646		76						-	-
503	923	923610	LABS US BS Indirect Allocs		-		-		2,825,559		1,393,767		3,119,418	132,236
504	923	923710	LABS US CS Indirect Allocs		-		-		75,124		65,370		9,754	414
505	923	923810	CENTRAL Indirect Allocs		-		-		1,556,517		387,924		2,402,221	101,834
506	923	923910	LIB Corp US CS Indirect Allocs		-		-		400,651		127,094		626,376	26,553
507	924	924000	Property Insurance		3,106,055		3,057,769		2,929,419		2,975,613		2,596,344	110,063
508	924	924001	Aviation Insurance		6,041		6,225		513		4,385		771	33
509	925	925000	Injuries & Damages-Corp		1,209,403		1,517,385		1,006,949		1,410,661		1,002,401	42,493
510	926	926000	Benefits Contra Account		-		-		(408,276)		(255,696)		(239,271)	(10,143)
511	926	926145	Pension SERP Defined Benefit		915,958		1,818,372		1,391,227		2,539,785		194,736	8,255
512	926	926146	FAS 87 SLCC Reimbursement		(45,996)		(25,681)		3,266		(11,082)		142	6
513	926	926147	FAS87 Reg Asset Amort Exp		(1,166,489)		(479,289)		1,203,932		93,227		1,685,032	71,431
514	926	926148	FAS87 Pens - Elec/Gas (GAAP)		8,980,612		8,254,023		7,485,568		8,388,819		5,795,133	245,664
515	926	926149	FAS87 Pens - Reg Asset (5yr)		611,310		620,746		594,495		603,101		(8,696)	(369)
516	926	926197	Pensions - Iatan		1,097,607		1,178,365		1,169,189		1,202,342		1,191,361	50,503
517	926	926201	Dental Plan		148,975		161,974		140,323		158,313		136,556	5,789
518	926	926202	Vision Plan		46,518		50,491		44,415		49,650		42,072	1,783
519	926	926212	Severence Benefits		-		-		-		-		525	22
520	926	926214	Employee Refreshments		-		-		59,495		8,302		95,981	4,069
521	926	926215	Comp Exp Employee Stk Purch		133,574		123,322		45,623		78,104		52,747	2,236
522	926	926216	Employee Information		14,050		14,440		12,831		16,441		11,682	495
523	926	926217	Flowers		2,581		2,489		1,349		2,058		1,272	54
524	926	926218	Coffeeroom Supplies		5,990		6,599		9,718		6,251		13,141	557
525	926	926219	Other Employee Benefits		61,862		82,212		79,523		96,471		77,343	3,279
526	926	926222	Group Life Insurance		180,689		167,590		194,321		154,484		291,082	12,339
527	926	926225	Executive Physicals		4,459		20,514		1,752		5,284		(148)	(6)
528	926	926226	Employee Welfare Exp - Elec		66,210		70,344		10,444		37,637		20,952	888
529	926	926227	Acc Death & Dismemb - Benefit		40,663		41,182		22,266		32,294		22,584	957
530	926	926230	Flex Benefit Plan Expense		9,869		(17,919)		16,085		23,123		4,764	202
531	926	926231	Tuition Reimbursement		42,465		47,051		38,661		41,065		41,976	1,779
532	926	926232	Taxable Educational Assistance		(67)		(39)		4		(17)		(0)	(0)
533	926	926326	FAS106 OPEB - Reg Amortization		(279,635)		(231,035)		(43,079)		(98,133)		(45,415)	(1,925)
534	926	926327	FAS106 HC - Reg Asst Amort Exp		(1,281,202)		133,358		2,320,041		1,355,140		2,141,379	90,776
535	926	926328	FAS106 HC - Elec/Gas (GAAP)		3,182,737		1,749,134		566,310		1,248,206		1,214,331	51,477
536	926	926329	Healthcare - Electric/Gas		7,559,282		7,441,460		7,278,743		8,605,916		5,200,695	220,465
537	926	926437	Employee Disability Plan Exp		122,343		114,053		134,998		123,743		126,321	5,355
538	926	926555	401K - Electric/Gas		1,663,740		1,615,362		1,540,229		1,665,116		1,485,355	62,966
539	929	929000	Duplicate Charges Credit		(207,453)		(273,295)		(276,978)		(298,353)		(276,657)	(11,728)
540	928	928000	Regulatory Commission Exp-Corp		1,398,638		1,208,653		1,340,377		1,245,552		1,321,445	103,350
541	928	928002	FERC Gen Formula Rate Case Exp		3,676		-		-		-		-	-
542	928	928003	FERC Tran Formula Rate Case Ex		11,822		5,279		-		-		-	-
543	930	930104	Franchise Elections		14,611		13,764		11,222		12,353		11,299	479
544	930	930106	Local Advertising		353		245		176		176		420	18
545	930	930219	E.D. Association Dues		8,777		8,515		6,515		8,435		7,095	301
546	930	930220	Dir-Stkhldr & Oth Investor Exp		2,406,195		2,925,371		487,000		1,611,508		441,586	18,719
547	930	930230	Conflict Resolution Hotline		3,431		3,444		3,719		7,163		-	-
548	930	930234	Other		8,700		9,000						-	-
549	930	930240	Misc Gen Exp-Other		17,754		18,077		16,104		10,348		40,198	1,704

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
550	930	930248	Chamber Of Commerce Dues		41,698		39,389		18,765		19,059		20,138	854
551	930	930298	External Merger Costs				8,219,220		5,871,677		14,090,897		-	-
552	930	930299	Invest Adv Srv – Acquisition				863,062		32,844,057		25,058,969		238,751	-
553	931	931026	Equipment Rental-Bld Serv		5,243		1,588		1,711		1,715		2,118	90
554	931	931281	Building Rental		121,039		120,838		40,324		88,511		5,985	254
555	931	930141	Institutional Ad - Radio		1,735		420				420		2,000	85
556	932	930143	Institutional Ad - Newspaper		713		-		1,425		425		-	-
557	932	930144	Institutional Ad - Other		19		850		600		1,450		-	-
558	933	930210	Industry Association Dues		177,740		204,233		193,355		202,505		219,686	9,313
559			**Total Other Administrative and General Expenses**		45,729,302		58,001,891		91,402,670		92,878,791		49,838,972	2,149,675
560			**Total Electric Operation Expenses:**		**$ 275,793,337**		**$ 270,122,505**		**$ 286,840,576**		**$ 296,124,170**		**$ 271,118,227**	**$ 11,459,642**

Tickmarks:
= Traced and Agreed To 12/15 Trial Balance
@ = Traced and Agreed To 12/16 Trial Balance
% = Traced and Agreed To 12/17 Trial Balance
^ = Traced and Agreed To 6/30/17 Trial Balance
* = Traced and Agreed To 06/30/18 Trial Balance

Line No.	FERC	GL Account	Description	Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
				Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1			**Maintenance Expense**											
2			**Maintenance Supervision Expenses:**											
3	510	510030	Mtce Supervision & Engineer	#	$ 784,226	@	$ 730,969	%	$ 952,000	^	$ 810,006	*	$ 1,158,398	$ 52,223
4	510	510994	Iatan2 Mtc Rg Adj Amortization		(103,672)		415,385		(32,737)		450,989		(32,737)	-
5	510	510995	IatCom Mtc Rg Adj Amortization		340,634		(418,129)		126,513		(500,666)		126,513	-
6	510	510996	PP Mtc Trk Rg Adj Amortization		(39,244)		(182,880)		18,385		(120,299)		18,385	-
7	510	510997	IatanII Mtc Rg Adj ER2011-0004		(54,191)		-		-		-		-	-
8	510	510998	IatCom Mtc Reg Adj ER2011-0004		(41,265)		-		-		-		-	-
9	510	510999	PP Mtc Trk Reg Adj ER2011-0004		(1,010,663)		-		-		-		-	-
10			**Total Maintenance Supervision Expenses:**		(124,175)		545,345		1,064,161		640,030		1,270,559	52,223
11			**Maintenance of Structures Expenses:**											
12	511	511127	Mtce Of Structures	#	866,679	@	946,130	%	1,216,821	^	984,677	*	1,318,683	62,400
13	511	511132	Mtce Of Structures - Environ		10,709		1,838		8,503		4,559		6,659	315
14	511	511135	Mtce Of Structures - Other		450,070		321,496		298,240		283,556		268,062	12,685
15	511	511176	Mtce Of Wastewater Treatment		1,466		1,218						-	-
16			**Total Maintenance of Structures Expenses:**		1,328,923		1,270,682		1,523,564		1,272,792		1,593,404	75,400
11			**Maintenance of Boiler Plant Expenses:**											
12	512	512138	Mtce Coalhandling	#	348,018	@	478,205	%	471,297	^	471,910	*	504,184	22,729
13	512	512139	Mtce Of Rotary Dumper		121,748		95,692		109,769		106,980		64,377	2,902
14	512	512141	Mtce Of Coal Sampler & Lab		1,321		2,470		4,287		6,575		183	8
15	512	512144	Mtce Of C.E.M. Equipment		87,963		51,253		16,843		35,622		207	9
16	512	512147	Mtce Of Coal Dozers		245,505		291,528		172,422		235,783		139,927	6,308
17	512	512150	Mtce Of Feeders		14,045		52,336		34,804		50,421		65,122	2,936
18	512	512153	Mtce Of Bottom & Fly Ash Syste		566,490		480,324		235,432		384,521		283,539	12,782
19	512	512156	Mtce Instrmnt & Meters Boiler		85,426		63,987		50,798		46,214		59,702	2,691
20	512	512159	Mtce Of Precipitator		24,406		3,133		-		-		-	-
21	512	512160	Mtce Of Furnace		473,169		581,948		264,983		162,124		573,034	25,833
22	512	512161	Mtce Of Cyclones		410,455		101,107		486,225		472,013		169,555	7,644
23	512	512162	Mtce Of Draft Systems		138,286		240,691		278,175		235,280		178,540	8,049
24	512	512163	Mtce Of Feedwater System Equip		164,861		148,176		70,837		129,323		374,992	16,905
25	512	512164	Mtce Of Fuel Oil & Igniter Sys		3,222		28,132		23,587		38,988		16,242	732
26	512	512165	Mtce Of Boiler Plant-Other		2,938,565		3,730,898		3,357,225		3,642,377		3,600,237	162,305
27	512	512166	Mtce Of Burners		-		104		49,580		49,684		-	-
28	512	512167	Mtce Of Boiler Drums & Headers		97,135		309,462		30,926		31,438		10,148	458
29	512	512168	Sel Catalytic Reduction - Mtce		58,317		125,699		29,514		95,511		30,846	1,391
30	512	512169	Mtce - Water Supply System		75,841		6,368		22,083		20,928		46,141	2,080
31			**Total Maintenance of Boiler Plant Expenses:**		5,854,773		6,791,514		5,708,788		6,215,692		6,116,977	275,764
32			**Maintenance of Electric Plant Expenses:**											
33	513	513122	Mtce Of Electrical Equipment	#	25,737	@	21,804	%	21,814	^	29,626	*	10,809	487
34	513	513168	Mtce Of Turbine Plant		1,185,379		814,923		1,445,482		1,459,142		1,793,953	80,874
35	513	513172	Mtce Of Turbine Inst. & Meters		2,335		4,429		12,844		9,281		28,970	1,306
36	513	513173	Mtce Of Hydrogen System		37		483		-		293		-	-
37	513	513174	Mtce Of Cooling Tower		135,576		118,768		69,400		76,501		85,782	3,867
38	513	513175	Mtce Of Cooling Lake		-		100,238		56,530		109,063		86,152	3,884
39	513	513178	Mtce Of Electrical Equipment		100,076		128,489		98,568		73,495		70,821	3,193
40	513	513181	Mtce Of Condensing Equipment		12,376		21,150		29,402		9,714		36,839	1,661
41	513	513182	Mtce Of Lube/Control Oil Equip		6,990		20,316		23,266		25,739		27,507	1,240
42			**Total Maintenance of Electric Plant Expenses:**		1,468,505		1,230,600		1,757,306		1,792,853		2,140,833	96,512
17			**Maintenance of Miscellaneous Steam Plant Expenses:**											
18	514	514144	Mtce of C.E.M. Equipment	#	17,443	@	21,530	%	41,299	^	33,700	*	63,151	2,988
19	514	514158	Mtc Of Auxiliary Plant Equip		658,831		341,079		346,898		309,236		289,987	13,722
20	514	514168	Mtce of SCR Catalytic Reducer		107,982		79,438		187,413		91,012		263,808	12,483
21	514	514171	Mtce Of Misc Steam Plant		117,518		146,080		90,592		79,392		166,784	7,892

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	**FERC**	**GL Account**	**Description**	**Reference**	**12/31/2015**	**Reference**	**12/31/2016**	**Reference**	**12/31/2017**	**Reference**	**6/30/2017**	**Reference**	**6/30/2018**	**6/30/2018**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
22	514	514173	Mtce of Scrubber		195,927		127,818		104,730		127,843		204,470	9,675
23	514	514174	Mtce of PAC System		-		-		-		-		159	8
24	514	514175	Mtce of BAMhouse		200,647		595,793		194,793		544,485		68,183	3,226
25	514	514176	Mtce of Hydrator		5,515		36,543		62,204		65,061		45,091	2,134
26			**Total Maintenance of Miscellaneous Steam Plant Expenses:**		1,303,862		1,348,281		1,027,928		1,250,729		1,101,631	52,129
27			**Maintenance Supervision and Engineering:**											
28	541	541304	Maint Supervision & Eng-Hydro	#	37,660	@	23,421	%	39,706	^	37,485	*	37,662	1,782
29			**Total Maintenance Supervision and Engineering:**		37,660		23,421		39,706		37,485		37,662	1,782
30			**Maintenance of Structures Expenses:**											
31	542	542307	House Expenses - Hydro	#	74,722	@	40,952	%	39,531	^	44,092	*	32,501	1,538
32	542	542337	Maint Of Structures - Hydro		3,993		4,420		14,249		12,774		10,606	502
33			**Total Maintenance of Structures Expenses:**		78,715		45,373		53,780		56,866		43,107	2,040
34			**Maintenance of Reservoirs, Dams, Water:**											
35	543	543334	Maint Reservoirs Dam & Waterwy	#	132,814	@	143,659	%	162,615	^	160,840	*	139,241	6,589
36			**Total Maintenance of Reservoirs, Dams, Water:**		132,814		143,659		162,615		160,840		139,241	6,589
37			**Maintenance of Electric Plant:**											
38	544	544340	Maint Of Electric Plant- Hydro	#	34,708	@	37,294	%	38,438	^	36,985	*	40,844	1,933
39			**Total Maintenance of Electric Plant:**		34,708		37,294		38,438		36,985		40,844	1,933
40			**Maintenance of Misc. Hydraulic Plant Expenses:**											
41	545	545343	Maint-Hydro Plt Not Recreation	#	36,949	@	14,383	%	70,682	^	38,957	*	58,014	2,745
42	545	545346	Maint-Misc Hydro Plt-Recreatn		89,686		168,102		38,808		108,562		27,497	1,301
43			**Total Maintenance of Misc. Hydraulic Plant Expenses:**		126,635		182,484		109,491		147,519		85,511	4,046
44			**Maintenance Supervision and Engineering:**											
45	551	551201	Maint Supervision & Engineer	#	436,301	@	586,271	%	781,280	^	700,153	*	799,898	37,851
46			**Total Maintenance Supervision and Engineering:**		436,301		586,271		781,280		700,153		799,898	37,851
47			**Maintenance of Structures Expenses:**											
48	552	552121	Exp of Structures	#	35,532	@	53,462	%	84,318	^	69,278	*	57,284	2,711
49	552	552122	Exp of Structures Fuel		2,889		2,297		2,238		2,429		2,106	100
50	552	552135	Mtce Of Structures - SL		59,040		99,103		162,518		101,825		237,725	11,249
51	552	552136	Mtce of Structures Fires		9,979		34,732		15,340		41,627		28,102	1,330
52	552	552137	Mtce of Structures Fuel		50,529		13,690		11,039		7,676		61,064	2,890
53			**Total Maintenance of Structures Expenses:**		157,969		203,284		275,454		222,835		386,280	18,279
54			**Maintenance of Generating and Electric Expenses:**											
55	553	553144	Mnt CEM Equip Combustion Turb	#	10,517	@	-	%	-	^	-	*		-
56	553	553157	Mtce of Duct Burners		-		(467)		9,758		9,128		3,003	142
57	553	553160	Mtce of Turbines		4,294,691		5,286,179		6,012,529		6,714,147		5,135,142	242,994
58	553	553161	Mtce of Turbine Aux Equip		165,906		91,545		232,009		174,621		248,358	11,752
59	553	553162	Mtce Of Hrsg Enclosure&Structr		39,361		107,201		12,056		105,700		18,913	895
60	553	553163	Mtce Of Hrsg Pressure Parts		1,858,977		20,478		330,108		108,539		741,225	35,075
61	553	553164	Mtce of Environmental Devices		80,157		108,654		159,650		139,942		141,527	6,697
62	553	553165	Mtce of Cooling Systems		84,993		138,887		133,870		176,870		204,127	9,659
63	553	553166	Mtce of Feedwater Systems		209,256		47,996		83,902		76,412		500,832	23,699
64	553	553167	Mtce of Steam & Wtr Systems		10,203		7,170		139,185		23,438		(16,688)	(790)
65	553	553168	Riverton Deferred Maintenance		2,720,248		3,528,307		5,505,654		4,973,552		5,467,337	258,713
66	553	553169	Riverton MtcTrk MO ER2014-0351		-		(1,553,785)		(3,159,832)		(3,335,768)		(3,245,745)	-
67	553	553170	Mtce of Generators		18,556		371,838		673,683		417,472		646,295	30,583
68	553	553171	Mtce of Gen Excitation Sys		291		7,968		47,798		31,493		59,049	2,794
69	553	553172	Mtce of Generator Aux Equip		1,450		399		14,689		9,451		10,358	490
70	553	553173	Mtce of Station Transformers		381		1,249		42,818		2,640		43,777	2,072
71	553	553174	Mtce of Accessory Elec Equip		94,933		120,628		63,642		72,506		131,972	6,245

Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	Kansas 6/30/2018
				Total Company										**Kansas**
				Calendar Years Ended						**Test Year**		**Test Year**		**Test Year**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
72	553	553175	Mtce of Elec Control System		48,964		31,312		202,051		120,950		179,930	8,514
73	553	553181	Mtce of Condenser		-		11,462		18,182		8,669		27,456	1,299
74	553	553182	Mtce of Auxiliary steam system		-		4,882		34,588		29,744		19,925	943
75	553	553184	Mtce of Cooling Water Supply		-		21,346		18,610		32,731		263,723	12,479
76	553	553228	Mtc Oth Gen&Elec Equip Wat Inj		35,474		32,554		39,564		40,829		44,121	2,088
77	553	553231	Maint Of Gen & Elect Eq-Other		938,637		1,426,808		1,202,773		797,939		3,031,420	143,446
78	553	553232	Unit #12 Combustion Turbine		678,539		56,635		(1,171)		4,502		3,309	157
79	553	553260	Mtce of Turbines - Unit 10,11		-		30,824		148,797		126,395		120,804	5,716
80			**Total Maintenance of Generating and Electric Expenses:**		11,291,534		9,900,071		11,964,912		10,861,899		13,780,169	805,663
81			**Maintenance of Misc. Other Power Expenses:**											
82	554	554110	Exp of Misc Power Plant Equip	#	29,411	@	82,279	%	91,332	^	101,295	*	83,948	3,972
83	554	554130	Mtce of Misc Plant Systems		227,263		229,450		311,935		308,621		246,951	11,686
84	554	554131	Mtce Of Misc Plant Tools		64,368		99,055		74,960		97,466		87,193	4,126
85	554	554234	Maint- Misc Oth Power Gen Plt		287,298		317,355		276,331		316,437		295,925	14,003
86			**Total Maintenance of Misc. Other Power Expenses:**		608,341		728,139		754,557		823,819		714,017	3
87			**Transmission Expenses:**											
88	568	568631	T & D Eng-Maint Supervision	#	217,844	@	213,374	%	132,282	^	188,813	*	117,706	5,570
89	569	569037	Trans Substa Structure Maint		9,762		5,892		8,567		1,761		9,330	441
90	569	569203	General Maint-System Ops		7,656		1,691		7,689		4,141		5,770	273
91	570	570040	Trans Substa Equip Maintenance		575,386		430,784		422,019		471,345		432,160	20,450
92	570	570043	Trans Sub Breaker Routine Mtce		-		128,357		120,260		193,850		60,422	2,859
93	570	570044	TransSub Trnsfrmr Routine Mtce		-		4,329		144,275		139,041		58,309	2,759
94	570	570060	Trans Substation Inspections		64,775		76,333		69,416		68,392		83,895	3,970
95	570	570177	Substation Maintenance - Plant		75,326		68,536		39,189		100,292		6,271	297
96	570	570472	Transmission-Relays & Misc Eq		290,600		315,024		368,468		339,712		362,165	17,138
97	570	570475	Generation - Relays & Misc Eq		28,067		40,968		36,879		42,389		39,913	1,889
98	570	570511	Protection Relaying Channel Eq		2,130		8,521		6,419		7,858		10,519	498
99	570	570517	Scada		248,593		280,650		359,932		309,257		339,044	16,043
100	571	571001	OH Trans Tree Trimming Superv		146,005		197,277		170,602		246,623		157,378	7,447
101	571	571041	Oh Trans Line Maint-161Kv		17,986		30,188		(15,242)		(3,500)		11,608	549
102	571	571042	Overhead Trans Line Maint-69Kv		101,422		51,022		30,298		45,010		31,965	1,513
103	571	571043	Oh Trans Line Maint-345 Kv		1,256		28,373		90,759		107,982		5,750	272
104	571	571044	Oh Trans Line Maint-34.5Kv		6,410		5,056		465		274		1,640	78
105	571	571045	Oh Trans Line Maint-Other		5,634		27,146		10,569		23,526		11,901	563
106	571	571046	Oh Trans Line Tree Trim-345 Kv		-		-		49,911		46,364	#	3,547	168
107	571	571047	Oh Trans Line Tree Trim-161Kv		14,851		11,396		28,385		38,343	#	1,733	82
108	571	571048	Oh Trans Line Tree Trim-69 Kv		57,612		60,453		110,882		122,135	#	87,375	4,135
109	571	571050	Oh Trans Ln Tree Trim-34.5 Kv		-		-		5,250		3,377		1,873	89
110	571	571051	Oh Trans Line Tree Trim-Other		240		-						-	-
111	571	571062	Trans OH reliab - labor&other		15,977		16,980		19,306		18,906		20,391	965
112	571	571146	Chemical Tree Trim 345Kv		39,388				52,572		50,131		2,441	115
113	571	571147	Chemical Tree Trim 161Kv		162,820		281,350		812,589		435,203		745,645	35,284
114	571	571148	Chemical Tree Trim 69Kv	#	328,936	@	272,726	%	326,494	^	119,141	*	529,611	25,061
115	571	571150	Chemical Tree Trim 34.5Kv		-		11,712				11,712		15,193	719
116	571	571246	Side Trimming 345Kv		-		1,418				1,418		-	-
117	571	571247	Side Trimming 161Kv		90,470		12,844				2,796		-	-
118	571	571248	Side Trimming 69Kv		109,987		111,795		28,981		60,809		8,766	415
119	571	571250	Side Trimming 34.5Kv				1,418		5,147		6,565		-	-
120	571	571346	Transm Tree Trimming 345Kv		885		594						-	-
121	571	571347	Transm Tree Trimming 161Kv		15,541		4,531		2,080		1,739		168	8
122	571	571348	Trans Tree Trimming 69Kv		90,128		5,761		765		6,449		-	-
123	571	571350	Transm Tree Trimming 34.5Kv		6,837		1,981		520		2,501		-	-
124	571	571447	Hydro-Ax Tree Trim 161Kv		65,204		3,422						14,490	686
125	571	571448	Hydro-Ax Tree Trim 69Kv		5,848		98,542		51,333		136,922		76,655	3,627
126	571	571450	Hydro-Ax Tree Trim 34.5Kv		-		-		250		250		-	-
127	571	571546	Tree Grinder-Tree Trim 345kv		-		1,534				1,534		-	-

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
128	571	571547	Tree Grinder-Tree Trim 161kv		5,213		4,458		13,468		13,468		1,092	52
129	571	571548	Tree Grinder-Tree Trim69kv		89,791		64,316		73,776		89,065		52,847	2,501
130	571	571646	Dozer-Tree Trim 345kv		-		-						9,419	446
131	571	571647	Dozer-Tree Trim 161kv		23,354		3,805		577		1,554		3,406	161
132	571	571648	Dozer-Tree Trim 69kv		2,976		-		172,430		149,260		23,827	1,128
133	571	571652	Trans 69Kv Pole Inspctn&Trmnt		-		-		35,000				37,512	1,775
134	571	571656	Trans 345Kv Pole Insptn&Trmnt		-		-		60,183				60,183	2,848
135	571	571658	Trans 34.5Kv Pole Insptn&Trmnt		-		225		426		2,672		(1,523)	(72)
136	571	571740	TGR Tree Trimming-Transmission		-		-		4,747		4,747		19,459	921
137	571	571910	Transm Maint 161KV Reliability		61,555		205,653		38,081		139,366		25,757	1,219
138	571	571911	Transm Maint 69KV Reliability		319,552		242,920		(64,495)		97,790		23,585	1,116
139	571	571912	Transm Maint 345KV Reliability		1,504		29,008		2,134		29,205		1,778	84
140	571	571913	Trans Maint 34.5KV Reliability		7,285		5,781		659		1,094		263	12
141	571	571920	Transm 69KV Pole Inspec Reliab		133,727		136,718		280,715		198,701		82,015	3,881
142	571	571921	Transm 161KV Pole Inspc Reliab		16,358		-						-	-
143	571	571998	Trans Reliab Reg Adj Amort		199,008		115,814		61,980		73,502		61,980	-
144	571	571999	Trans Reliability Reg Adj		199,278		(83,209)				(83,209)		-	-
145			**Total Transmission Expenses:**		**3,863,176**		**3,537,463**		**4,176,994**		**4,070,279**		**3,655,235**	**170,032**
146			**Distribution Expenses**											
147	590	590001	Supervision Distribution Maint	#	110,961	@	91,011	%	93,622	^	93,586	*	89,380	4,915
148	590	590620	GIS Maintenance/Updates						46,192		32,118		25,627	1,409
149	590	590630	Line Eng Distribution Maint		128,780		129,855		129,157		125,915		152,731	8,399
150	591	591024	Building Maint-Line Operations		27,648		34,940		63,958		50,872		81,042	4,457
151	591	591049	Dist Substa Structure Maint		15,876		12,008		5,881		8,724		7,162	394
152	591	591103	General Maint. - Meter Shop		72		-		171		171		-	-
153	591	591403	General Maint. - GarAMe		7,010		8,050		1,735		3,183		3,298	181
154	591	591503	General Maint. - 4Th & Rr		1,487		112		49		49		-	-
155	592	592052	Dist Substation Equip Maint		1,475,799		1,194,676		888,849		1,056,036		1,125,395	61,886
156	592	592053	Dist Sub Breaker Routine Mtce		-		105,358		144,509		144,230		140,231	7,711
157	592	592054	Dist Sub Trnsfrmr Routine Mtce		-		380,652		383,057		579,169		224,796	12,362
158	592	592060	Dist Substation Inspections		291,393		214,105		229,911		216,422		206,883	11,377
159	592	592469	Distribution-Relays & Misc Eq		78,115		87,334		74,666		91,578		85,545	4,704
160	593	593001	OH Dist Line Tree Trimming Spr		1,023,684		1,020,448		1,102,101		1,075,716		1,033,882	56,854
161	593	593011	Conv & Seminar - Tree Trimming		8,675		5,676		11,587		8,582		7,236	398
162	593	593025	Safety Expense - Tree Trimming		1,004		341		1,186		357		2,132	117
163	593	593058	Oh Dist Line Tree Trimming		4,094,609		3,379,502		2,920,039		2,974,803		3,196,561	175,781
164	593	593062	Dist OH reliab - labor & other		228,104		208,757		294,267		258,766		270,966	14,901
165	593	593158	Chemical Tree Trim 12Kv		732,659		989,674		1,390,186		1,026,192		1,705,413	93,782
166	593	593258	Side Trimming 12Kv		289,759		142,976		129,380		202,907		78,059	4,292
167	593	593458	Hydro-Ax Tree Trimming 12 Kv		153,718		1,075,236		967,085		1,206,808		843,352	46,376
168	593	593500	Misc Repair Expense		9,635		6,966		9,885		10,611		8,737	480
169	593	593510	General Office Expense		47,256		107,476		107,741		99,874		74,342	4,088
170	593	593555	Oh Dist Line Maintenance		2,999,409		2,696,200		2,190,185		2,750,223		2,221,991	122,188
171	593	593556	OhDist Line Capacitor BankMtce		-		80,955		100,816		156,823		19,544	1,075
172	593	593558	Tree Grinder-Tree Trim 12kv		1,282,662		669,991		526,589		403,097		390,582	21,478
173	593	593560	OH Dist Line Oper Storms		10,796		1,084		8,701		3,109		5,729	315
174	593	593570	Reclosers Sect & Oil Switches		67,102		65,768		116,664		107,950		88,751	4,880
175	593	593575	Misc Repair & Testing		48,841		38,808		40,384		32,879		34,476	1,896
176	593	593597	May 2011 Tornado O&M Amort		84,402		84,402		84,402		84,402		84,402	-
177	593	593598	2009 Wind Storm Amortization		92,153		4,956				2,478		-	-
178	593	593599	Amortization-ice storm expense		157,445		139,909		132,681		132,681		132,681	132,681
179	593	593658	Dozer-Tree Trim 12kv		43,719		8,381		14,193		6,379		10,990	604
180	593	593740	TGR Tree Trimming-Distribution		531,805		954,657		594,479		848,340		922,502	50,729
181	593	593910	OH Dist Line Maint Reliability		578,354		979,919		590,220		1,008,294		605,822	33,314
182	593	593920	OH Dist Pole Inspc Reliability		500,171		617,263		556,762		464,580		819,654	45,073
183	593	593930	General Office Exp Reliability		(716)		787		15		7		30	2
184	593	593931	Janitor/Bldg Maint-Reliability		12		-						-	-

				Total Company										Kansas
				Calendar Years Ended						Test Year		Test Year		Test Year
Line No.	FERC	GL Account	Description	Reference	12/31/2015	Reference	12/31/2016	Reference	12/31/2017	Reference	6/30/2017	Reference	6/30/2018	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
185	593	593932	Utilities Exp - Reliability		2,556		3,585		3,493		3,435		4,047	223
186	593	593940	Reliability Wildlife Cover Up		-		106,574		11,694		113,956		4,335	238
187	593	593998	Dist OH Reliab Reg Adj Amort		1,149,480		667,972		357,478		423,931		357,478	-
188	593	593999	Dist OH Reliability Reg Adj		1,396,039		(479,914)				(479,914)		-	-
189	594	594061	Underground Dist Line Maint		690,478		590,184		468,554		577,966		424,770	23,358
190	594	594062	Dist UG reliab - labor & other		19,034		20,540		22,798		23,676		23,242	1,278
191	594	594910	Dist UG Line Maint Reliability		157,843		160,950		169,408		182,143		166,578	9,160
192	594	594998	Dist UG Reliab Reg Adj Amort		55,172		31,808		17,023		20,187		17,023	-
193	594	594999	Dist UG Reliability Reg Adj		53,709		(22,853)				(22,853)		-	-
194	595	595064	Dist Transformer Maintenance		2,815		1,900		5,108		4,001		3,797	209
195	595	595161	Overhead Transformers - Old		398,935		409,854		402,759		412,026		388,455	21,361
196	595	595164	Underground Transformers - Old		44,716		34,462		37,375		39,908		37,540	2,064
197	596	596067	Strt Light&Signal Sys Maint Ex		365,857		304,686		318,133		311,332		303,822	16,707
198	597	597123	Shop Test & Repair		332,139		304,964		328,164		327,468		312,931	17,208
199	597	597138	Load Research Equipment Repair		23,113		29,293		40,776		32,546		41,483	2,281
200	598	598073	Maint Of Misc Distrib Plant		255,240		227,331		268,086		215,477		244,291	13,434
201			**Total Distribution Expenses:**		**20,069,527**		**17,929,571**		**16,402,152**		**17,453,198**		**17,029,715**	**1,036,623**
202			**Other Administrative and General Expenses**											
203	935	935024	Building & Grounds Maintenance	#	202,169	@	234,235	%	227,234	^	205,072	*	250,608	10,624
204	935	935026	Building Maintenance		217,023		284,924		284,832		309,155		285,006	12,082
205	935	935027	Bldg Maint EDE owned rent prop		-		926		(17)		(9)		(6)	(0)
206	935	935098	Computer Maintenance		15,356		19,898		15,584		19,871		15,978	677
207	935	935099	Computer Mtce-Customer Watch		2		1		(0)		1		-	-
208	935	935289	Supplies-Info Serv		8,209		(351)		(3)		(324)		2	0
209	935	935346	Furniture Maintenance		2,041		423		32		339		35	1
210	935	935347	Telephone System Maintenance		(11)		(6)		1		(3)		0	0
211	935	935389	Office Equipment Maintenance		(806)		12		525		270		(4)	(0)
212	935	935515	Microwave Maintenance Expenses		30,260		58,446		52,057		44,634		56,691	2,403
213	935	935520	Telephone Expenses-Telecomm		286		1,669		570		843		280	12
214	935	935523	Telecomm Exp Other		5,335		7,651		11,213		14,539		12,115	514
215			**Total Other Administrative & General:**		**479,864**		**607,829**		**592,028**		**594,387**		**620,705**	**26,313**
216			**Total Electric Maintenance Expenses:**		**$ 47,149,133**		**$ 45,111,281**		**$ 46,433,155**		**$ 46,338,360**		**$ 49,555,788**	**$ 2,663,180**

Tickmarks:
= Traced and Agreed To 12/15 Trial Balance

			Total Company				
			Calendar Years Ended			Prior Test Year End	Test Year End
Line No.	**Description**	**Reference**	**12/31/2015**	**12/31/2016**	**12/31/2017**	**6/30/2017**	**6/30/2018**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Power Generated (Kilowatt Hours)	Sch 1 Financial Statements	$ 5,281,594,000	$ 5,290,272,980	$ 5,156,585,170	$ 5,208,285,120	$ 5,464,867,420
2	Electric Sales (Kilowatt Hours):						
3	Residential		1,836,254,614	1,825,014,393	1,745,674,302	1,784,669,305	1,939,432,178
4	Commercial		1,577,416,185	1,588,302,946	1,560,478,989	1,562,846,466	1,616,593,367
5	Industrial		1,064,481,097	1,073,675,003	1,080,149,098	1,073,686,934	1,105,179,180
6	Public Street And Highway Lighting		24,356,647	24,324,918	24,371,109	24,572,527	24,333,816
7	Other Sales To Public Authorities		102,429,654	104,244,699	102,228,902	103,961,420	104,038,303
8	Interdepartmental		4,302,591	3,198,317	2,634,043	2,487,783	2,911,246
9	Sales For Resale - On-System		330,787,112	331,947,412	325,819,752	327,948,646	339,159,665
10	Sales For Resale - Off-System						
11	Total Sales Of Electricity		4,940,027,900	4,950,707,688	4,841,356,195	4,880,173,081	5,131,647,755
12	Customers (Average):						
13	Residential		142,555	143,555	144,718	144,085	145,300
14	Commercial		24,311	24,501	24,644	24,579	24,698
15	Industrial		352	350	350	349	351
16	Public Street And Highway Lighting		486	495	504	499	513
17	Other Sales To Public Authorities		1,596	1,587	1,578	1,576	1,580
18	Interdepartmental		42	41	41	41	41
19	Sales For Resale - On-System		4	4	4	4	4
20	Sales For Resale - Off-System						
21	Total Average Customers	Sch 1 Financial Statements	169,346	170,533	171,839	171,133	172,487
22	Electric Operating Revenues:						
23	Residential	WP-8.2 Revenue	230,571,500	236,618,843	238,334,587	235,294,419	266,511,967
24	Commercial	WP-8.2 Revenue	171,727,135	172,219,226	175,235,495	169,950,039	185,854,262
25	Industrial	WP-8.2 Revenue	88,185,220	86,238,172	88,720,987	85,517,177	93,999,760
26	Public Street And Highway Lighting	WP-8.2 Revenue	4,178,397	4,115,107	4,173,789	4,144,972	4,257,545
27	Other Sales To Public Authorities	WP-8.2 Revenue	11,094,471	11,144,497	11,254,224	11,121,510	11,793,735
28	Sales For Resale - On-System	WP-8.2 Revenue	18,031,526	19,723,905	19,110,853	19,683,975	20,120,325
29	Sales For Resale - Off-System	WP-8.2 Revenue	15,045,095	24,098,260	33,325,432	33,517,054	35,919,250
30	Interdepartmental	WP-8.2 Revenue	443,785	344,461	304,189	290,844	335,631
31	Total Sales Of Electricity		539,277,129	554,502,472	570,459,558	559,519,989	618,792,475
32	Other Electric Operating Revenues		13,752,716	12,202,564	12,251,776	11,561,463	12,502,471
33	Total Electric Operating Revenues		553,029,845	566,705,037	582,711,334	571,081,452	631,294,945
34	Average Annual Kwh Sales Per Customer-Residential	Line 3 / Line 13	12,881	12,713	12,063	12,386	13,348
35	Average Annual Kwh Sales Per Customer-Commercial	Line 4 / Line 14	64,885	64,826	63,321	63,585	65,454
36							
37	Average Annual Rate Per Kilowatt-Hour-Residential	Line 23 / Line 3	0.1256	0.1297	0.1365	0.1318	0.1374
38	Average Annual Rate Per Kilowatt-Hour-Commercial	Line 24 / Line 4	0.1089	0.1084	0.1123	0.1087	0.1150
39	Average Annual Revenue Per Customer - Residential	Line 23 / Line 13	1,617	1,648	1,647	1,633	1,834
40	Average Annual Revenue Per Customer - Commercial	Line 24 / Line 14	$ 7,064	$ 7,029	$ 7,111	$ 6,914	$ 7,525

Line No.	Description	Reference	Kansas				
			Calendar Years Ended			Prior Test Year End	Test Year End
			12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Power Generated (Kilowatt Hours)						
2	Electric Sales (Kilowatt Hours):	12 MOE Electric Revenue Summary by Rate					
3	Residential		$ 107,531,677	$ 104,985,463	$ 101,755,784	$ 105,605,361	$ 110,027,834
4	Commercial		52,975,569	51,507,385	50,753,707	52,110,513	52,157,081
5	Industrial		61,435,166	59,764,813	61,632,113	60,832,969	62,290,325
6	Public Street And Highway Lighting		1,780,496	1,794,522	1,767,416	1,778,585	1,772,823
7	Other Sales To Public Authorities		4,407,777	4,192,608	3,878,960	4,117,448	3,895,887
8	Interdepartmental		499,660	199,108	122,455	104,782	161,170
9	Sales For Resale - On-System		12,275,689	10,318,020	9,627,300	9,775,312	10,413,404
10	Sales For Resale - Off-System						
11	Total Sales Of Electricity		240,906,034	232,761,919	229,537,735	234,324,970	240,718,524
12	Customers (Average):						
13	Residential		8,219	8,205	8,196	8,205	8,189
14	Commercial		1,222	1,233	1,261	1,248	1,267
15	Industrial		49	49	50	48.58	51
16	Public Street And Highway Lighting		57	55	54	54	54
17	Other Sales To Public Authorities		119	111	102	103	102
18	Interdepartmental		4	4	4	4	4
19	Sales For Resale - On-System		1	1	1	1	1
20	Sales For Resale - Off-System						
21	Total Average Customers		9,671	9,659	9,668	9,664	9,670
22	Electric Operating Revenues:						
23	Residential	Operating Allocation Worksheet	12,126,316	11,371,975	11,348,838	11,122,179	12,431,473
24	Commercial	Operating Allocation Worksheet	6,214,555	5,806,111	5,936,910	5,737,269	6,176,544
25	Industrial	Operating Allocation Worksheet	5,214,454	4,779,072	5,101,815	4,776,208	5,278,289
26	Public Street And Highway Lighting	Operating Allocation Worksheet	260,162	254,506	257,446	251,390	261,544
27	Other Sales To Public Authorities	Operating Allocation Worksheet	537,697	490,272	468,065	472,336	481,944
28	Sales For Resale - On-System	Operating Allocation Worksheet	729,787	691,504	722,929	692,422	-
29	Sales For Resale - Off-System	Operating Allocation Worksheet	736,622	1,116,343	1,623,918	1,745,643	1,507,495
30	Interdepartmental	Operating Allocation Worksheet	60,396	32,719	25,805	24,079	30,824
31	Total Sales Of Electricity		25,879,989	24,542,502	25,485,726	24,821,526	26,168,113
32	Other Electric Operating Revenues	Operating Allocation Worksheet	637,951	534,812	508,015	490,605	(56,921)
33	Total Electric Operating Revenues		26,517,940	25,077,314	25,993,741	25,312,131	26,111,192
34	Average Annual Kwh Sales Per Customer-Residential	Line 3 / Line 13	13,083	12,795	12,415	12,871	13,436
35	Average Annual Kwh Sales Per Customer-Commercial	Line 4 / Line 14	43,337	41,766	40,259	41,753	41,152
36							
37	Average Annual Rate Per Kilowatt-Hour-Residential	Line 23 / Line 3	0.1128	0.1083	0.1115	0.1053	0.1130
38	Average Annual Rate Per Kilowatt-Hour-Commercial	Line 24 / Line 4	0.1173	0.1127	0.1170	0.1101	0.1184
39	Average Annual Revenue Per Customer - Residential	Line 23 / Line 13	1,475	1,386	1,385	1,356	1,518
40	Average Annual Revenue Per Customer - Commercial	Line 24 / Line 14	$ 5,084	$ 4,708	$ 4,709	$ 4,597	$ 4,873

The Empire District Electric Company
Kansas
Docket No. 19-EPDE-XXX-RTS
Section 8
WP-8.5 Annual Payroll

			Total Company						Kansas Jurisdiction	
			Calendar Years Ended			Prior Test Year End	Test Year End	Test Year End	Test Year End	
Line No.	Description	Reference	12/31/2015	12/31/2016	12/31/2017	6/30/2017	6/30/2018	Clearing Account	Allocation Factor (1)	6/30/2018
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Production	Fin Stmt Schedule IIA	$ 17,242,769	$ 17,046,844	$ 18,364,002	$ 17,916,903	$ 18,052,158	$ 2,442,266	4.42%	$ 905,448
2	Transmission		2,628,368	2,655,005	2,724,661	2,826,473	2,398,294	324,463.90	4.42%	120,292
3	Distribution		9,550,642	9,356,074	9,039,681	9,471,396	9,165,967	1,240,058.58	4.42%	459,741
4	Customer Accounts		4,534,534	4,603,162	4,832,722	4,680,044	4,888,371	661,344.92	4.42%	245,188
5	Customer Service		1,496,950	1,354,012	1,376,703	1,429,549	1,442,376	195,138.20	4.42%	72,346
6	Sales		120,229	103,600	98,144	100,233	101,283	13,702.57	4.42%	5,080
7	Administrative and General		13,880,486	16,440,085	14,208,829	14,853,601	13,613,907	1,841,818	4.42%	682,837
8	Total Operations and Maintenance		49,453,977	51,558,781	50,644,743	51,278,200	49,662,356	6,718,792		2,490,932
9	Construction Work in Progress	Fin Stmt Schedule II	8,780,036	8,699,712	9,657,737	8,570,334	8,988,665	1,216,071	5.01%	511,766
10	Retirement Work in Progress	Fin Stmt Schedule II	1,995,565	2,196,519	1,974,439	2,261,000	1,678,657	227,105	5.01%	95,574
11	Water and Non-Utility	Fin Stmt Schedule IIA	4,837,066	4,829,861	4,611,571	4,779,201	4,760,476	304,689		
12	Clearing Accounts	Fin Stmt Schedule II	7,113,211	7,192,892	8,266,626	7,739,965	8,466,658	(8,466,658)		
13	Total Payroll		$ 72,179,855	$ 74,477,765	$ 75,155,116	$ 74,628,700	$ 73,556,812	$ -		$ 3,098,271

Footnote:
(1) Allocation Factor 4ST06-18 Kansas Expense to total company expense

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company: Ending Balance	Total Company: Pro Forma Adjustments	Total Company: As Adjusted Under Present Rates	Kansas: Ending Balance	Kansas: Pro Forma Adjustments	Kansas: As Adjusted Under Present Rates
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Electric Utility Operating Revenues:							
2	Electric Operating Service Revenue	**WP-9.3 Revenue Detail**	$ 618,792,475	$ (9,267,619)	$ 609,524,856	$ 26,168,113	$ (9,267,619)	$ 16,900,494
3	Other Electric Operating Revenues	**WP-9.3 Revenue Detail**	12,502,471		12,502,471	(56,921)		(56,921)
4	Total Electric Utility Operating Revenue		631,294,945	(9,267,619)	622,027,327	26,111,192	(9,267,619)	16,843,573
5	Electric Utility Operating Expenses:							
6	Production	**WP 9.4 Expense Detail**	206,647,698	(5,829,564)	200,818,134	8,672,796	(5,829,564)	2,843,232
7	Transmission	**WP 9.4 Expense Detail**	25,075,914	(1,224,251)	23,851,663	1,224,251	(1,224,251)	-
8	Distribution	**WP 9.4 Expense Detail**	25,438,528	26,445	25,464,973	1,499,028	26,445	1,525,473
9	Customer Account Expense	**WP 9.4 Expense Detail**	8,754,321	49,312	8,803,633	490,707	49,312	540,019
10	Customer Assistance	**WP 9.4 Expense Detail**	4,144,157	5,372	4,149,528	87,232	5,372	92,603
11	Sales Expenses	**WP 9.4 Expense Detail**	153,719	378	154,097	6,605	378	6,983
12	Administrative & General Expenses	**WP 9.4 Expense Detail**	1,321,445	125,423	1,446,868	103,350	125,423	228,773
13	Other Administrative & General Expenses	**WP 9.4 Expense Detail**	50,545,875	373,849	50,919,724	1,960,202	373,849	2,334,051
14	Depreciation & Amortization Expense	**WP-10 Depreciation & Amortization**	80,344,732	259,763	80,604,495	3,885,270	259,763	4,145,032
15	Taxes other than Income	**WP- 11 Taxes Detail**	36,469,544	(632,555)	35,836,989	1,741,052	(632,555)	1,108,497
16	Interest on Customer Deposits	**WP 9.1 Int Exp on Cust Deposits**		7,062	7,062		7,062	7,062
17	Total Electric Utility Operating Expense	**Sum Line 6 through 16**	438,895,933	(6,838,768)	432,057,165	19,670,492	(6,838,768)	12,831,724
18	Net Operating Income (Loss) Before Taxes	**Line 4 - Line 17**	192,399,012	(2,428,851)	189,970,161	6,440,699	(2,428,851)	4,011,848
19	State Income Taxes	**WP-11 Taxes Detail**	5,762,100	4,499,427	10,261,527	187,846	(26,126)	161,720
20	Federal Income Taxes	**WP-11 Taxes Detail**	58,437,989	(26,449,557)	31,988,432	1,749,341	(1,458,008)	291,333
21	Total Taxes		64,200,089	(21,950,130)	42,249,959	1,937,187	(1,484,134)	453,053
22	Net Operating Income After Taxes	**Line 18 - Line 21**	$ 128,198,923	$ 19,521,279	$ 147,720,202	$ 4,503,512	$ (944,717)	$ 3,558,796

Test Year Ending June 30, 2018

Line No.	Description	Weather Norm Revenue Adjustment 2018	Unbilled Revenue	Revenue Adjustment Franchise Fee	Revenue Adjustment Ad Valorem Tax Surcharge Rider	Customer Deposit Int. Exp. Adj.	Revenue Adjustment Asbury Riverton Environmental Rider (AERR)	Revenue Adjustment Fuel ECA
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Adjustment Number**	**ADJ-13**	**ADJ-27**	**ADJ-26**	**ADJ-24**	**Section 12**	**ADJ-25**	**ADJ-23**
2	Revenues	$ (195,088)	$ (160,692)	$ (471,195)	$ (555,293)	**$** -	$ (1,794,980)	$ (5,119,783)
3	Production							
4	Transmission Expenses							
5	Distribution Expenses							
6	Customer Account Expense							
7	Customer Service & Informational Expense							
8	Sales Expenses							
9	Administrative & General Expenses							
10	Other Administrative & General Expenses							
11	Depreciation & Amortization Expense							
12	Taxes other than Income							
13	Interest on Customer Deposit					7,062		
14	Total Operating & Maintenance Expenses (Sum of Line 3 through Line 13)	-	-	-	-	7,062	-	-
15	Income Taxes							
16	Net Operating Income (Loss) After Taxes (Line 2 - Line 14 - Line 15)	$ (195,088)	$ (160,692)	$ (471,195)	$ (555,293)	$ (7,062)	$ (1,794,980)	$ (5,119,783)

		Test Year Ending June 30, 2018							
Line No.	**Description**	**Merit Increase**	**Plum Point Contract Update**	**Fuel ECA**	**TDC Adjustment**	**Uncollectible Exp. Adj.**	**Rate Case Expense Adjustment**	**Pension and OPEB Adjustment**	**Annualized Depreciation Adjustment**
	(a)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	**Adjustment Number**	**ADJ-16**	**ADJ-14**	**ADJ-15**	**ADJ-17**	**ADJ-8**	**ADJ-7**	**ADJ-18**	**See Section 10**
2	Revenues	$ -	$ -	$ (1,507,495)	$ (53,808)	$ -	$ -	$ -	$ -
3	Production	18,928	12,488	(5,885,048)	(14,492)				
4	Transmission Expenses				(1,224,251)				
5	Distribution Expenses	11,329							
6	Customer Account Expense	6,002				31,082			
7	Customer Service & Informational Expense	1,769							
8	Sales Expenses	124							
9	Administrative & General Expenses						213,730		
10	Other Administrative & General Expenses	14,073			(212,605)			653,136	
11	Depreciation & Amortization Expense	632							250,291
12	Taxes other than Income	4,689			(168,185)				
13	Interest on Customer Deposit								
14	Total Operating & Maintenance Expenses (Sum of Line 3 through Line 13)	57,547	12,488	(5,885,048)	(1,619,534)	31,082	213,730	653,136	250,291
15	Income Taxes								
16	Net Operating Income (Loss) After Taxes (Line 2 - Line 14 - Line 15)	$ (57,547)	$ (12,488)	$ 4,377,553	$ 1,565,726	$ (31,082)	$ (213,730)	$ (653,136)	$ (250,291)

Test Year Ending June 30, 2018

Line No.	Description	Medical, Dental & Vision Expense	Franchise Tax Adjustment	Open Positions	Overtime Adjustment	Non Deductible Expense	Federal Income Tax Adjustment	State Income Tax Adjustment	CWIP Adjustment
	(a)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	**Adjustment Number**	**ADJ-12**	**See Section 11**	**ADJ-9**	**ADJ-28**	**ADJ-19**	**See Section 11**	**See Section 11**	**ADJ-5**
2	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Production			34,520	4,040	(1)			
4	Transmission Expenses								
5	Distribution Expenses			20,661	2,418	(24)			
6	Customer Account Expense			10,947	1,281				
7	Customer Service & Informational Expense			3,226	377				
8	Sales Expenses			227	27				
9	Administrative & General Expenses								
10	Other Administrative & General Expenses	139,838		25,665	3,003	(250)			
11	Depreciation & Amortization Expense								9,872
12	Taxes other than Income		(471,290)						2,894
13	Interest on Customer Deposit								
14	Total Operating & Maintenance Expenses (Sum of Line 3 through Line 13)	139,838	(471,290)	95,246	11,146	(275)	-	-	12,766
15	Income Taxes						(1,458,008)	(26,126)	
16	Net Operating Income (Loss) After Taxes (Line 2 - Line 14 - Line 15)	$ (139,838)	$ 471,290	$ (95,246)	$ (11,146)	$ 275	# $ (1,458,008)	$ (26,126)	$ (12,766)

		Test Year Ending June 30, 2018				
Line No.	**Description**	**Iatan & Plum Point Prudency**	**Tax Reform Rev. Adj.**	**A&G Expense Adjustment**	**Prior Rate Case Amort. Overage Adj.**	**Total Kansas Pro Forma Adjustments**
	(a)	(y)	(z)	(aa)	(bb)	(cc) = SUM (b) through (bb)
1	**Adjustment Number**	**ADJ-1**	**ADJ-3**	**ADJ-6**	**ADJ-10**	
2	Revenues	$ -	$ 590,715	$ -	$ -	$ (9,267,619)
3	Production					(5,829,564)
4	Transmission Expenses					(1,224,251)
5	Distribution Expenses				(7,939)	26,445
6	Customer Account Expense					49,312
7	Customer Service & Informational Expense					5,372
8	Sales Expenses					378
9	Administrative & General Expenses				(88,307)	125,423
10	Other Administrative & General Expenses			(249,011)		373,849
11	Depreciation & Amortization Expense	(1,033)				259,763
12	Taxes other than Income	(663)				(632,555)
13	Interest on Customer Deposit					7,062
14	Total Operating & Maintenance Expenses (Sum of Line 3 through Line 13)	(1,695)	-	(249,011)	(96,246)	(6,838,768)
15	Income Taxes					(1,484,134)
16	Net Operating Income (Loss) After Taxes (Line 2 - Line 14 - Line 15)	$ 1,695	$ 590,715	$ 249,011	$ 96,246	$ (944,717)

Test Year Ending June 30, 2018

Line No.	Adj. No.	FERC	Reference	Total Company Increase	Total Company Decrease	Kansas Increase	Kansas Decrease	Adjustment Explanation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	ADJ-1	403	WP ADJ 1-Iatan and Plum Point Prudency		1,033		1,033	To adjust depreciation expense for Iatan 11-EPDE-856-RTS
2	ADJ-1	408	WP ADJ 1-Iatan and Plum Point Prudency		663		663	To adjust Property Taxes for Iatan 11-EPDE-856-RTS
3					1,695		1,695	Adjustment 1 Total
4	ADJ-6	Various	WP ADJ 6 A&G Expense		-		249,011	To remove A&G related expenses as part of merger stip
5	ADJ-7	928	WP ADJ 7 Rate Case Expense	213,730		213,730		To recognize current Kansas rate case expense
6	ADJ-8	904	WP ADJ 8 Uncollectible Expense	-		31,082		Adjustment to Normalize Uncollectible Expense to a 5 year average. Adjustment to Uncollectible Expense for anticipated rate increase.
7	ADJ-9	Various	WP ADJ 9 Open Positions	2,395,340		95,246		To recognize open positions for labor expense
8	ADJ-10	593 & 928	WP ADJ 10 Prior Rate Case Amort Overage Adj		96,246		96,246	Adjustment for the over collection of Amort of 2009 KS Rate case Exp & 2009 Wind Storm
9	ADJ-12	926	WP ADJ 12 Medical, Dental & Vision	-		139,838		To adjust health care, dental, and vision expenses to a 5 year average. To adjust expenses to reflect 2019 contract year for known increases/decreases
10	ADJ-13	440	WP ADJ 13 Weather Norm Revenue Adjustment 2018		122,461		122,461	To normalize weather - residential
11	ADJ-13	442	WP ADJ 13 Weather Norm Revenue Adjustment 2018		38,715		38,715	To normalize weather - commercial
12	ADJ-13	442	WP ADJ 13 Weather Norm Revenue Adjustment 2018		33,911		33,911	To normalize weather - industrial
13					195,088		195,088	Total normalized weather
14	ADJ-14	555	WP ADJ 14 Plum Point Contract Update	-		12,488		To adjust demand charges from Plum Point
15	ADJ-15	447	WP ADJ 15 Fuel ECA		1,507,495		1,507,495	To remove fuel and purchased power revenue that flows through ECA Rider
16	ADJ-15	Various	WP ADJ 15 Fuel ECA	-			5,885,048	To remove fuel and purchased power expenses that flows through ECA Rider
17	ADJ-16	403	WP ADJ 16 Merit increase	-		632		To recognize wage increases
18	ADJ-16	Various	WP ADJ 16 Merit increase	-		52,226		To recognize wage increases
19	ADJ-16	408	WP ADJ 16 Merit Increase	-		4,689		To increase (decrease) payroll taxes resulting from payroll adj.
20				-		57,547		Adjustment 16 Total
21	ADJ-17	408	WP ADJ 17 TDC Adjustment		-		168,185	To remove Transmission Taxes Other Than Income Taxes TFR for TDC Rider
22	ADJ-17	Various	WP ADJ 17 TDC Adjustment		-		1,451,348	To remove Transmission Expenses TFR for TDC Rider
23					-		1,619,533	Total
24	ADJ-17	Various	WP ADJ 17 TDC Adjustment		-		53,808	To remove Transmission Revenue TFR for TDC Rider
25	ADJ-18	926	WP ADJ 18 Penson and OPEB	-		653,136		To adjust Pension and OPEB to actuarial report
26	ADJ-19	Various	WP ADJ 19 Non-Deductible Expenses		6,354		275	To remove non deductible expenses recorded above the line on books
27	ADJ-23	440	WP - ADJ 23, 24, 25, 26		2,440,398		2,440,398	To remove fuel and purchased power - residential
28	ADJ-23	442	WP - ADJ 23, 24, 25, 26		1,163,603		1,163,603	To remove fuel and purchased power - commercial
29	ADJ-23	442	WP - ADJ 23, 24, 25, 26		1,386,018		1,386,018	To remove fuel and purchased power - industrial
30	ADJ-23	444	WP - ADJ 23, 24, 25, 26		39,604		39,604	To remove fuel and purchased power - muni street & highway lightingl
31	ADJ-23	445	WP - ADJ 23, 24, 25, 26		86,617		86,617	To remove fuel and purchased power - other public authority
32	ADJ-23	448	WP - ADJ 23, 24, 25, 26		3,544		3,544	To remove fuel and purchased power - interdepartmental
33					5,119,783		5,119,783	Adjustment 23 Total

Test Year Ending June 30, 2018

				Total Company		Kansas		
Line No.	**Adj. No.**	**FERC**	**Reference**	**Increase**	**Decrease**	**Increase**	**Decrease**	**Adjustment Explanation**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
34	ADJ-24	440	**WP - ADJ 23, 24, 25, 26**		265,732		265,732	To remove Ad Valorem Tax Surcharge Rider Revenue - Res
35	ADJ-24	442	**WP - ADJ 23, 24, 25, 26**		125,862		125,862	To remove Ad Valorem Tax Surcharge Rider Revenue - Com
36	ADJ-24	442	**WP - ADJ 23, 24, 25, 26**		149,682		149,682	To remove Ad Valorem Tax Surcharge Rider Revenue - Ind
37	ADJ-24	444	**WP - ADJ 23, 24, 25, 26**		4,278		4,278	To remove Ad Valorem Tax Surcharge Rider Revenue - muni street & highway lighting
38	ADJ-24	445	**WP - ADJ 23, 24, 25, 26**		9,352		9,352	To remove Ad Valorem Tax Surcharge Rider Revenue - other public authority
39	ADJ-24	448	**WP - ADJ 23, 24, 25, 26**		388		388	To remove Ad Valorem Tax Surcharge Rider Revenue - interdepartmental
40					555,293		555,293	Adjustment 24 Total
41	ADJ-25	440	**WP - ADJ 23, 24, 25, 26**		853,451		853,451	To remove Asbury & Riverton Environmental Rider Revenue AERR - Res
42	ADJ-25	442	**WP - ADJ 23, 24, 25, 26**		402,682		402,682	To remove Asbury & Riverton Environmental Rider Revenue AERR - Comm
43	ADJ-25	442	**WP - ADJ 23, 24, 25, 26**		493,498		493,498	To remove Asbury & Riverton Environmental Rider Revenue AERR - Ind
44	ADJ-25	444	**WP - ADJ 23, 24, 25, 26**		14,061		14,061	To remove Asbury & Riverton Environmental Rider Revenue AERR - muni street and public lighting
45	ADJ-25	445	**WP - ADJ 23, 24, 25, 26**		30,012		30,012	To remove Riverton Rider Revenue - Other Public Authority
46	ADJ-25	448	**WP - ADJ 23, 24, 25, 26**		1,278		1,278	To remove Riverton Rider Revenue - Interdepartmental
47					1,794,982		1,794,980	Adjustment 25 Total
48	ADJ-26	440	**WP - ADJ 23, 24, 25, 26**		379,668		379,668	To remove franchise fee Revenue - Residential
49	ADJ-26	442	**WP - ADJ 23, 24, 25, 26**		86,677		86,677	To remove franchise fee Revenue - Commercial
50	ADJ-26	442	**WP - ADJ 23, 24, 25, 26**		4,852		4,852	To remove franchise fee Revenue - Industrial
51	ADJ-26	444	**WP - ADJ 23, 24, 25, 26**		-		-	To remove franchise fee Revenue - Muni Street & Highway Lighting
52	ADJ-26	445	**WP - ADJ 23, 24, 25, 26**		-		-	To remove franchise fee Revenue - Other Public Authority
53	ADJ-26	448	**WP - ADJ 23, 24, 25, 26**		(2)		(2)	To remove franchise fee Revenue - Interdepartmental
54					471,195		471,195	Adjustment 26 Total
55	ADJ-27	Various	**WP - ADJ 27**		120,141		120,141	To remove unbilled revenue - Residential
56	ADJ-27	Various	**WP - ADJ 27**		32,230		32,230	To remove unbilled revenue - Commercial
57	ADJ-27	Various	**WP - ADJ 27**		8,321		8,321	To remove unbilled revenue - Industrial
58					160,692		160,692	Adjustment 27 Total
59	ADJ-28	Various	**WP ADJ 28 Overtime Expense**	-		11,146		To normalize and adjust overtime expense for merit increase
60	ADJ-3	254	**WP-3.1 Reg Asset and Liabality Summary**	590,715		590,715		Tax Reform
61	Section 12	440-442	**WP-Customer Deposits and Interest**	7,062		7,062		Include Customer Deposit Interest in Operating Income
62	Section 10	408	**WP-10 Normalized Depr Calc**	-		250,291		To annualize depreciation expense
63	ADJ-5	See CWIP P1-P14	**WP ADJ 5 CWIP**	-		9,872		To adjust depreciation expense for plant additions
64	Section 11	408910, 408930	**WP-11a Taxes Detail**		-		471,290	To Remove Franchise Tax Expense
65	ADJ 5	See CWIP	**WP ADJ 5 CWIP**	112,243		2,894		To adjust Property Taxes for Plant Additions
66	Section 11	409	**WP-11.4 Calc Tax Simp**	(26,449,557)		(1,458,008)		To adjust federal book taxes
67	Section 11	409	**WP-11.4 Calc Tax Simp**	4,499,427		(26,126)		To adjust state book taxes

Test Year Ending June 30, 2018

Line No.	FERC	Description	Reference	Total Company Ending Balance	Reclass	Total Company Adjusted Ending Balance	Kansas Ending Balance		Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)		(h)	(i) = (g) + (h)
1		Production:								
2	403	Steam	Section-10 Depr Summary	$ 27,820,853	$ -	$ 27,820,853	$ 904,237		$ 390,281	$ 1,294,518
3	403	Hydro	Section-10 Depr Summary	192,118	-	192,118	7,436		6,560	13,996
4	403	Other	Section-10 Depr Summary	6,966,614	-	6,966,614	362,935		231,499	594,435
5		**Total Production**	Section-10 Depr Summary	34,979,586	-	34,979,586	1,274,608	(1)	628,341	1,902,949
6	403	Transmission	Section-10 Depr Summary	7,700,066	-	7,700,066	413,149		(413,149)	-
7	403	Distribution	Section-10 Depr Summary	30,729,784	-	30,729,784	1,858,526		(36,349)	1,822,177
8	403	General	Section-10 Depr Summary	3,009,647	-	3,009,647	152,963		80,758	233,721
9		**Total Depreciation Expense**		76,419,083	-	76,419,083	3,699,247		259,601	3,958,847
10		Amortization of Electric Plant								
11	403	Other Amortization	Section-10 Amort Summary	216,307		216,307	-		-	-
12	404	Amort Ltd-Term Elect/Gas Plant	Section-10 Amort Summary	3,709,342		3,709,342	186,023		162	186,185
13		**Total Amortization Expense**		3,925,649	-	3,925,649	186,023	(2)	162	186,185
14		**Total Depreciation & Amortization Expense**		$ 80,344,732	$ -	$ 80,344,732	$ 3,885,270		$ 259,763	$ 4,145,032

Footnote:
(1) Allocated to Kansas from Total Company Electric Utility Plant based on Production, Transmission, Distribution and General Plant Subtotal
(2) Accounts are direct assigned

Test Year Ending June 30, 2018

Line No.	FERC	Description	Reference	Total Company Ending Balance	Reclass	Total Company Revised Ending Balance	Allocation Percentage	Kansas Ending Balance	Annualized Depreciation Expense Adjustment	Iatan and Plum Point Prudency Adjustment	CWIP Adjustment	Merit Increase Adjustment	Adjusted Kansas Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j)	(k)	(l)	(m) = SUM (h) through (l)
1		**Adjustment Number**							**Section 10**	**ADJ-1**	**ADJ-5**	**ADJ-16**	
DEPRECIATION EXPENSE													
2	403	Steam	Sum of 12 months WP Dper Calc	$ 27,820,853	$ -	$ 27,820,853	3.25%	$ 904,237	$ 386,894	$ (1,033)	$ 4,246	$ 174	$ 1,294,518
3	403	Hydro	Sum of 12 months WP Dper Calc	192,118	-	192,118	3.87%	7,436	6,526	-	32	1	13,996
4	403	Other	Sum of 12 months WP Dper Calc	6,966,614	-	6,966,614	5.21%	362,935	228,336	-	3,094	70	594,435
5		Total Production Plant		34,979,586	-	34,979,586		1,274,608	621,756	(1,033)	7,372	245	1,902,949
6	403	Transmission Plant	Sum of 12 months WP Dper Calc	7,700,066	-	7,700,066	5.37%	413,149	(413,149)	-	-	-	-
7	403	Distribution Plant	Sum of 12 months WP Dper Calc	30,729,784	-	30,729,784	6.05%	1,858,526	(38,162)	-	1,455	358	1,822,177
8	403	General Plant	Sum of 12 months WP Dper Calc	3,009,647	-	3,009,647	5.08%	152,963	79,846	-	883	29	233,721
9	403	Total Depreciation Expense		$ 76,419,083	$ -	$ 76,419,083		$ 3,699,247	$ 250,291	$ (1,033)	$ 9,710	$ 632	$ 3,958,847

Test Year Ending June 30, 2018

Line No.	GL Account	Description	Reference	Total Company Ending Balance	Pro Forma Adjustment	Total Company Adjusted Ending Balance	Kansas Ending Balance		CWIP Adjustment	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)		(h)	(i) = (g) + (h)
1		**Ajdustment Number**							**ADJ-5**	
2		Amortization of Electric Plant								
3	403003	MO Iat I Amrt O&M ER-2010-0130	WP Amortization Exp	$ 40,693	$ -	$ 40,693	$ -		$ -	$ -
4	403009	MO Iat II Amrt O&M ER-2011-0004	WP Amortization Exp	40,400		40,400	-		-	-
5	403011	MO PlmPt Amrt O&M ER-2011-0004	WP Amortization Exp	665		665	-		-	-
6	403012	Def Deprec 5-22-11 tornado	WP Amortization Exp	134,549		134,549	-		-	-
7	404000	Amort Ltd-Term Elect/Gas Plant	WP Amortization Exp	3,709,342		3,709,342	186,023		162	186,185
8		**Total Amortization of Electric Plant**		$ 3,925,649	$ -	$ 3,925,649	$ 186,023	(1)	$ 162	$ 186,185

Footnote:
(1) Accounts are direct assigned

Description	FERC	Description	Kansas: Test Year Ending 6/30/18 Plant Balance (1)	TDC Adjustment	Adjusted Test Year Ending 6/30/18 Balance	Proposed Depreciation Rates	Total Proposed Annual Depreciation Expense	Test Year Depreciation Expense	Annualized Depreciation Adjustment
(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j) = (h) - (i)
Adjustment Number				**ADJ-17**					
310R	310	Land	$ -	$ -	$ -	0.00%	$ -	$ -	$ -
311R	311	Structures	8,111	-	8,111	11.52%	934		
312R	312	Boiler Plant	3,038	-	3,038	11.52%	350		
314R	314	Turbogenerators	-	-	-	11.52%	-		
315R	315	Access. Electric	517	-	517	11.52%	60		
316R	316	Misc. Equipment	-	-	-	11.52%	-		
RIVERTON			**11,666**		**11,666**		**1,344**		
310A	310	Land	63,881	-	63,881	0.00	-		
311A	311	Structures	996,920	-	996,920	4.48%	44,662		
312A	312	Boiler Plant	10,379,150	-	10,379,150	5.61%	582,270		
312AT	312	(Unit Train)	-	-	-	5.43%	-		
314A	314	Turbogenerators	1,739,887	-	1,739,887	5.22%	90,822		
315A	315	Access. Electric	325,864	-	325,864	3.80%	12,383		
316A	316	Misc. Equipment	117,648	-	117,648	4.38%	5,153		
ASBURY			**13,623,350**		**13,623,350**		**735,290**		
310I	310	Land	5,756	-	5,756	0.00%	-		
311I	311	Structures	193,826	-	193,826	1.96%	3,799		
312I	312	Boiler Plant	3,617,838	-	3,617,838	3.25%	117,580		
312IT	312	(Unit Train)	15,568	-	15,568	6.67%	1,038		
314I	314	Turbogenerators	717,319	-	717,319	2.88%	20,659		
315I	315	Access. Electric	401,981	-	401,981	3.67%	14,753		
316I	316	Misc. Equipment	64,767	-	64,767	2.41%	1,561		
IATAN 1			**5,017,054**		**5,017,054**		**159,389**		
311I2	311	Structures	978,503	-	978,503	2.92%	28,572		
311.05	311	Reg Plan Amort	-	-	-	0.00%	-		
312I2	312	Boiler Plant	6,817,504	-	6,817,504	1.96%	133,623		
312.05	312	Reg Plan Amort	-	-	-	0.00%	-		
314I2	314	Turbogenerators	2,315,369	-	2,315,369	1.54%	35,657		
314.05	314	Reg Plan Amort	-	-	-	0.00%	-		
315I2	315	Access. Electric	591,800	-	591,800	1.60%	9,469		
315.05	315	Reg Plan Amort	-	-	-	0.00%	-		
316I2	316	Misc. Equipment	16,436	-	16,436	4.18%	687		
316.05	316	Reg Plan Amort	-	-	-	0.00%	-		

Description	FERC	Description	Kansas Test Year Ending 6/30/18 Plant Balance (1)	TDC Adjustment	Adjusted Test Year Ending 6/30/18 Balance	Proposed Depreciation Rates	Total Proposed Annual Depreciation Expense	Test Year Depreciation Expense	Annualized Depreciation Adjustment
(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j) = (h) - (i)
Adjustment Number				**ADJ-17**					
IATAN 2			**10,719,612**		**10,719,612**		**208,008**		
310IC	310	Land	342	-	342	0.00%	-		
311IC	311	Structures	749,625	-	749,625	2.92%	21,889		
312IC	312	Boiler Plant	1,842,495	-	1,842,495	1.96%	36,113		
314IC	314	Turbogenerators	61,234	-	61,234	1.54%	943		
315IC	315	Access. Electric	228,158	-	228,158	1.60%	3,651		
316IC	316	Misc. Equipment	32,920	-	32,920	4.18%	1,376		
IATAN COMMON			**2,914,774**		**2,914,774**		**63,972**		
310P	310	Land	45,263	-	45,263	0.00%	-		
311P	311	Structures	973,263	-	973,263	2.18%	21,217		
312P	312	Boiler Plant	2,550,997	-	2,550,997	2.17%	55,357		
312PT	312	(Unit Train)	246,479	-	246,479	6.67%	16,440		
314P	314	Turbogenerators	814,417	-	814,417	2.18%	17,754		
315P	315	Access. Electric	255,811	-	255,811	2.12%	5,423		
316P	316	Misc. Equipment	140,467	-	140,467	2.07%	2,908		
PLUM POINT			**5,026,697**		**5,026,697**		**119,099**		
Disallowances (Added Back into Rate Base)			**127,499**	**-**	**127,499**	3.16%	**4,029**		
TOTAL STEAM PRODUCTION PLANT:			**37,440,652**		**37,440,652**		**1,291,131**	**904,237**	**386,894**
330	330	Land	10,717	-	10,717	0.00%	-		
331	331	Structures	38,383	-	38,383	2.39%	917		
332	332	Dams	161,769	-	161,769	1.93%	3,122		
333	333	Turbogenerators	212,106	-	212,106	3.11%	6,596		
334	334	Access. Electric	69,990	-	69,990	3.14%	2,198		
335	335	Misc. Equipment	30,827	-	30,827	3.66%	1,128		
TOTAL HYDRO PRODUCTION PLANT:			**523,792**		**523,792**		**13,962**	**7,436**	**6,526**
340E	340	Land	7,718	-	7,718	0.00%	-		
341E	341	Structures	109,572	-	109,572	1.61%	1,764		
342E	342	Fuel Holders	61,175	-	61,175	0.00%	-		
343E	343	Prime Movers	1,288,281	-	1,288,281	2.93%	37,747		

Description	FERC	Description	Kansas Test Year Ending 6/30/18 Plant Balance (1)	TDC Adjustment	Adjusted Test Year Ending 6/30/18 Balance	Proposed Depreciation Rates	Total Proposed Annual Depreciation Expense	Test Year Depreciation Expense	Annualized Depreciation Adjustment
(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j) = (h) - (i)
Adjustment Number				**ADJ-17**					
344E	344	Generators	261,470	-	261,470	0.00%	-		
345E	345	Access. Electric	103,179	-	103,179	5.55%	5,726		
346E	346	Misc. Equipment	85,865	-	85,865	0.00%	-		
ENERGY CENTER UNITS 1 & 2			**1,917,260**		**1,917,260**		**45,237**		
341FT	341	Structures	53,277	-	53,277	3.27%	1,742		
342FT	342	Fuel Holders	66,458	-	66,458	2.99%	1,987		
343FT	343	Prime Movers	2,320,971	-	2,320,971	3.26%	75,664		
344FT	344	Generators	29,580	-	29,580	3.20%	947		
345FT	345	Access. Electric	161,145	-	161,145	3.15%	5,076		
346FT	346	Misc. Equipment	49,301	-	49,301	3.12%	1,538		
ENERGY CENTER FT8 UNITS 3 & 4			**2,680,733**		**2,680,733**		**86,954**		
340	340	Land	11,981	-	11,981	0.00%	-		
RIVERTON COMMON			**11,981**		**11,981**		**-**		
341R	341	Structures	381,878	-	381,878	4.51%	17,223		
342R	342	Fuel Holders	26,216	-	26,216	2.87%	752		
343R	343	Prime Movers	333,767	-	333,767	1.85%	6,175		
344R	344	Generators	84,205	-	84,205	2.36%	1,987		
345R	345	Access. Electric	73,440	-	73,440	3.13%	2,299		
346R	346	Misc. Equipment	49,006	-	49,006	4.00%	1,960		
RIVERTON CT UNITS 9, 10, 11			**948,512**		**948,512**		**30,396**		
341R12	341	Structures	843,166	-	843,166	2.42%	20,405		
342R12	342	Fuel Holders	44,746	-	44,746	3.22%	1,441		
343R12	343	Prime Movers	7,161,507	-	7,161,507	2.01%	143,946		
344R12	344	Generators	1,010,435	-	1,010,435	2.05%	20,714		
345R12	345	Access. Electric	1,254,893	-	1,254,893	2.64%	33,129		
346R12	346	Misc. Equipment	124,640	-	124,640	2.11%	2,630		
RIVERTON UNIT 12			**10,439,386**		**10,439,386**		**222,265**		
340S	340	Land	563	-	563	0.00%	-		
341S	341	Structures	52,482	-	52,482	0.00%	-		
342S	342	Fuel Holders	150,823	-	150,823	1.59%	2,398		
343S	343	Prime Movers	1,179,874	-	1,179,874	2.42%	28,553		

			Kansas						
Description	**FERC**	**Description**	**Test Year Ending 6/30/18 Plant Balance (1)**	**TDC Adjustment**	**Adjusted Test Year Ending 6/30/18 Balance**	**Proposed Depreciation Rates**	**Total Proposed Annual Depreciation Expense**	**Test Year Depreciation Expense**	**Annualized Depreciation Adjustment**
(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j) = (h) - (i)
Adjustment Number				**ADJ-17**					
344S	344	Generators	235,734	-	235,734	1.41%	3,324		
345S	345	Access. Electric	134,645	-	134,645	1.85%	2,491		
346S	346	Misc. Equipment	7,037	-	7,037	3.77%	265		
STATE LINE CT UNIT 1			**1,761,157**		**1,761,157**		**37,031**		
341SC	341	Structures	144,510	-	144,510	2.19%	3,165		
342SC	342	Fuel Holders	10,730	-	10,730	0.00%	-		
343SC	343	Prime Movers	29,883	-	29,883	2.07%	619		
344SC	344	Generators	-	-	-	2.50%	-		
345SC	345	Access. Electric	9,384	-	9,384	2.74%	257		
346SC	346	Misc. Equipment	46,873	-	46,873	2.46%	1,153		
STATE LINE COMMON			**241,380**	**-**	**241,380**		**5,194**		
340C	340	Land	39,694	-	39,694	0.00%	-		
341C	341	Structures	373,339	-	373,339	2.19%	8,176		
342C	342	Fuel Holders	12,611	-	12,611	0.00%	-		
343C	343	Prime Movers	5,110,333	-	5,110,333	2.07%	105,784		
344C	344	Generators	1,433,518	-	1,433,518	2.50%	35,838		
345C	345	Access. Electric	408,151	-	408,151	2.74%	11,183		
346C	346	Misc. Equipment	130,632	-	130,632	2.46%	3,214		
STATE LINE CC			**7,508,277**		**7,508,277**		**164,195**		
TOTAL OTHER PRODUCTION PLANT:			**25,508,686**		**25,508,686**		**591,271**	**362,935**	**228,336**
TOTAL PRODUCTION			**63,473,130**	**-**	**63,473,130**	**-**	**1,896,364**	**1,274,608**	**621,756**
350	350	Land	564,211	(564,211)	-	0.00%	-		
352	352	Structures	153,897	(153,897)	-	1.82%	-		
352I	352	Structures (Iatan)	1,089	(1,089)	-	1.82%	-		
353	353	Station Equip.	7,729,755	(7,729,755)	-	2.23%	-		
353I	353	Station Eq. (Iatan)	28,570	(28,570)	-	2.23%	-		
354	354	Towers & Fixtures	90,910	(90,910)	-	1.54%	-		
355	355	Poles & Fixtures	4,508,907	(4,508,907)	-	3.51%	-		
356	356	OH Conductor	4,558,056	(4,558,056)	-	1.71%	-		

			Kansas						
Description	**FERC**	**Description**	**Test Year Ending 6/30/18 Plant Balance (1)**	**TDC Adjustment**	**Adjusted Test Year Ending 6/30/18 Balance**	**Proposed Depreciation Rates**	**Total Proposed Annual Depreciation Expense**	**Test Year Depreciation Expense**	**Annualized Depreciation Adjustment**
(a)	(b)	(c)	(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) x (g)	(i)	(j) = (h) - (i)
Adjustment Number				**ADJ-17**					
TRANSMISSION			**17,635,395**	**(17,635,395)**	**-**		**-**	**413,149**	**(413,149)**
360	360	Land	219,428	-	219,428	0.00%	-		
361	361	Structures	693,149	-	693,149	1.56%	10,813		
362	362	Station Equip.	4,696,247	-	4,696,247	2.19%	102,848		
364	364	Poles & Fixtures	18,779,538	-	18,779,538	4.00%	751,182		
365	365	OH Conductor	13,624,784	-	13,624,784	3.39%	461,880		
366	366	UG Conduit	659,590	-	659,590	2.62%	17,281		
367	367	UG Conductor	802,117	-	802,117	2.58%	20,695		
368	368	Transformers	5,576,568	-	5,576,568	2.08%	115,993		
369	369	Services	4,572,969	-	4,572,969	4.44%	203,040		
370	370	Meters	1,401,538	-	1,401,538	2.37%	33,216		
371	371	Private Lights	1,553,946	-	1,553,946	4.43%	68,840		
373	373	Street Lights	990,744	-	990,744	3.49%	34,577		
375	375	Charging Stations	-	-	-	0.00%	-		
DISTRIBUTION			**53,570,620**	**-**	**53,570,620**		**1,820,364**	**1,858,526**	**(38,162)**
399	399	Land	53,054	(5,834)	47,220	0.00%	-		
390	390	Structure	597,512	(65,704)	531,809	2.75%	14,625		
391	391	Furniture	315,130	(34,652)	280,478	4.76%	13,351		
391C	391	Computer Equip.	758,664	(83,424)	675,240	10.00%	67,524		
392	392	Transport. Equip.	732,166	(80,510)	651,656	7.15%	46,593		
393	393	Stores Equip.	43,388	(4,771)	38,617	2.50%	965		
394	394	Tools	355,924	(39,138)	316,786	5.00%	15,839		
395	395	Lab Equipment	100,029	(10,999)	89,029	2.17%	1,932		
396	396	Power Op. Equip.	920,488	(101,219)	819,269	5.65%	46,289		
397	397	Communication	597,268	(65,677)	531,591	4.76%	25,304		
398	398	Misc. Equipment	13,903	(1,529)	12,375	3.13%	387		
GENERAL			**4,487,526**	**(493,456)**	**3,994,070**		**232,809**	**152,963**	**79,846**
TOTAL ELECTRIC UTILITY DEPRECIATION EXPENSE			**$ 139,166,671**	**$ (18,128,852)**	**$ 121,037,820**		**$ 3,949,538**	**$ 3,699,247**	**$ 250,291**

Footnote:
(1) Balances from Section 4: Plant

Acct	Account Name	Kansas Depreciation Rates: Depreciation Study Proposed	Kansas Depreciation Rates: Existing
(a)	(c)	(d)	(d)
	Riverton Steam Production		
311	Structures And Improvements	11.52%	1.05%
312	Boiler Plant And Equipment	11.52%	1.86%
314	Turbo Generator Units	11.52%	1.59%
315	Accessory Electric Equipment	11.52%	1.79%
316	Miscellaneous Power Plant Equipment	11.52%	1.96%
	Asbury Steam Production		
311	Structures And Improvements	4.48%	1.06%
312	Boiler Plant And Equipment	5.61%	1.87%
312.7	Unit Train	5.43%	6.67%
314	Turbo Generator Units	5.22%	1.60%
315	Accessory Electric Equipment	3.80%	1.79%
316	Miscellaneous Power Plant Equipment	4.38%	1.95%
	Iatan I Steam Production		
311	Structures And Improvements	1.96%	1.06%
312	Boiler Plant And Equipment	3.25%	1.89%
312.5	Unit Train	6.67%	6.67%
314	Turbo Generator Units	2.88%	1.62%
315	Accessory Electric Equipment	3.67%	1.81%
316	Miscellaneous Power Plant Equipment	2.41%	1.95%
	Iatan Common Steam Production		
311	Structures And Improvements	2.92%	1.06%
312	Boiler Plant And Equipment	1.96%	1.89%
314	Turbo Generator Units	1.54%	1.62%
315	Accessory Electric Equipment	1.60%	1.81%
316	Miscellaneous Power Plant Equipment	4.18%	1.95%
	Ozark Beach Hydro		
331	Structures And Improvements	2.39%	1.66%
332	Reservoirs, Dams And Waterways	1.93%	1.67%
333	Water Wheels, Turbines And Generators	3.11%	1.47%
334	Accessory Electric Equipment	3.14%	1.44%
335	Miscellaneous Power Plant Equipment	3.66%	2.44%
	Riverton Combustion Turbine UNITS 9, 10, & 11		
341	Structures And Improvements	4.51%	1.82%
342	Fuel Holders, Producers & Accessories	2.87%	3.85%
343	Prime Movers	1.85%	1.92%
344	Generators	2.36%	1.82%
345	Accessory Electric Equipment	3.13%	3.57%
346	Miscellaneous Power Plant Equipment	4.00%	4.00%
	Energy Center Combustion Turbine Units 1 & 2		

Acct	Account Name	Kansas Depreciation Rates: Depreciation Study Proposed	Kansas Depreciation Rates: Existing
341	Structures And Improvements	1.61%	1.82%
342	Fuel Holders, Producers & Accessories	0.00%	3.85%
343	Prime Movers	2.93%	1.92%
344	Generators	0.00%	1.82%
345	Accessory Electric Equipment	5.55%	3.57%
346	Miscellaneous Power Plant Equipment	0.00%	4.00%
	State Line Combustion Turbine		
341	Structures And Improvements	0.00%	1.82%
342	Fuel Holders, Producers & Accessories	1.59%	3.85%
343	Prime Movers	2.42%	1.93%
344	Generators	1.41%	1.82%
345	Accessory Electric Equipment	1.85%	3.57%
346	Miscellaneous Power Plant Equipment	3.77%	3.99%
	Energy Center Aero Units 3 & 4		
341	Structures And Improvements	3.27%	1.82%
342	Fuel Holders, Producers & Accessories	2.99%	3.85%
343	Prime Movers	3.26%	1.92%
344	Generators	3.20%	1.82%
345	Accessory Electric Equipment	3.15%	3.57%
346	Misc Power Plant Equipment	3.12%	3.99%
	State Line Combined Cycle		
341	Structures And Improvements	2.19%	2.86%
342	Fuel Holders, Producers & Accessories	0.00%	2.86%
343	Prime Movers	2.07%	2.86%
344	Generators	2.50%	2.86%
345	Accessory Electric Equipment	2.74%	2.86%
346	Miscellaneous Power Plant Equipment	2.46%	2.86%
	Plum Point		
311	Structures and Improvements	2.18%	1.06%
312	Boiler Plant and Equipment	2.17%	1.89%
312	Train	6.67%	6.67%
314	Turbo Generator Units	2.18%	1.62%
315	Accessory Electric Equipment	2.12%	1.81%
316	Miscellaneous Power Plant Equipment	2.07%	1.95%
	Iatan II		
311	Structures and Improvements	2.92%	1.06%
312	Boiler Plant and Equipment	1.96%	1.89%
314	Turbo Generator Units	1.54%	1.62%
315	Accessory Electric Equipment	1.60%	1.81%
316	Miscellaneous Power Plant Equipment	4.18%	1.95%
	Riverton Unit 12		

Acct	Account Name	Kansas Depreciation Rates: Depreciation Study Proposed	Kansas Depreciation Rates: Existing
341	Structures And Improvements	2.42%	1.82%
342	Fuel Holders, Producers & Accessories	3.22%	3.85%
343	Prime Movers	2.01%	1.92%
344	Generators	2.05%	1.82%
345	Accessory Electric Equipment	2.64%	3.57%
346	Miscellaneous Power Plant Equipment	2.11%	4.00%
	Total Production Plant:	3.16%	
352	Structures And Improvements	1.82%	2.09%
353	Station Equipment	2.23%	2.20%
354	Towers And Fixtures	1.54%	1.92%
355	Poles And Fixtures	3.51%	3.33%
356	Overhead Conductors And Devices	1.71%	2.15%
	Total Transmission Plant:	2.43%	
361	Structures And Improvements	1.56%	2.08%
362	Station Equipment	2.19%	1.89%
364	Poles, Towers And Fixtures	4.00%	4.35%
365	Overhead Conductors And Devices	3.39%	3.77%
366	Underground Conduit	2.62%	3.92%
367	Underground Conductors And Devices	2.58%	3.59%
368	Line Transformers	2.08%	2.78%
369	Services	4.44%	5.00%
370	Meters	2.37%	2.27%
371	Installations On Customers' Premises	4.43%	5.80%
373	Street Lighting And Signal Systems	3.49%	3.13%
	Total Distribution Plant:	3.15%	
390	Structures And Improvements	2.75%	2.75%
391.1	Office Furniture And Equipment	4.76%	5.00%
391.2	Computer Equipment	10.00%	10.00%
392	Transportation Equipment	7.15%	7.08%
393	Stores Equipment	2.50%	3.17%
394	Tools, Shop And Garage Equipment	5.00%	4.50%
395	Laboratory Equipment	2.17%	2.63%
396	Power Operated Equipment	5.65%	6.33%
397	Communication Equipment	4.76%	4.00%
398	Miscellaneous Equipment	3.13%	4.55%
	Total General Plant:	6.00%	

Test Year Ending June 30, 2018

Line No.	Description	Reference	Total Company Ending Balance	Pro Forma Adjustments	Total Company Adjusted Ending Balance	Kansas Ending Balance	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e)= (c) + (d)	(f)	(g)	(h) = (f) + (g)
	Taxes Other Than Income Taxes							
1	Payroll Taxes Contra Account	WP-11 Taxes Detail	$ (43,148)		$ (43,148)	$ (1,829)	$ (58)	$ (1,887)
2	Federal Insurance Contribution Act	WP-11 Taxes Detail	3,158,761		3,158,761	133,904	(10,132)	123,773
3	Payroll Taxes - Iatan	WP-11 Taxes Detail	227,743		227,743	9,654	307	9,962
4	Federal Unemployment	WP-11 Taxes Detail	21,613		21,613	916	29	945
5	State Unemployment	WP-11 Taxes Detail	107,494		107,494	4,557	145	4,702
6	Real and Property	WP-11 Taxes Detail	22,384,123		22,384,123	1,122,560	(151,557)	971,003
7	Corporation Franchise	WP-11 Taxes Detail	27,032		27,032	95	(95)	-
8	City Tax or Fee	WP-11 Taxes Detail	10,585,926		10,585,926	471,195	(471,195)	-
9	Total Taxes Other Than Income Taxes		36,469,544	-	36,469,544	1,741,052	(632,555)	1,108,497
10	**Income Taxes**							
11	State Income Taxes	WP-11 Taxes Detail	5,762,100		9,703,753	187,846	(26,126)	161,720
12	Federal Income Taxes	WP-11 Taxes Detail	58,437,989		30,249,674	1,749,341	(1,458,009)	291,333
13	Total Income Taxes		64,200,089	-	39,953,427	1,937,187	(1,484,135)	453,053
14	Total Taxes Chargeable to Operations		$ 100,669,633	$ -	$ 76,422,971	$ 3,678,240	$ (2,116,690)	$ 1,561,550

Test Year Ending June 30, 2018

			Kansas Jurisdiction						
Line No.	**Description**	**Reference**	**Iatan and Plum Point Prudency Adjustment**	**Merit Increase Adjustment**	**TDC Adjustment**	**CWIP Adjustment**	**Removal of Franchise Tax Expense Adjustment**	**Excess ADIT Amortizaton Adjustment**	**Total Kansas Pro Forma Adjustments**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = SUM (c) - (h)
1	**Adjustment Number**		**ADJ-1**	**ADJ-16**	**ADJ-17**	**ADJ-5**	**Section 11**	**ADJ-20**	
	Taxes Other Than Income Taxes								
2	Payroll Taxes Contra Account			$ (58)					$ (58)
3	Federal Insurance Contribution Act			4,265	(14,397)				(10,132)
4	Payroll Taxes - Iatan			307					307
5	Federal Unemployment			29					29
6	State Unemployment			145					145
7	Real and Property	Section 9 Operate income WP 9.2	(663)		(153,789)	2,894			(151,557)
8	Corporation Franchise	WP-11.1 Taxes Detail					(95)		(95)
9	City Tax or Fee	WP-11.1 Taxes Detail					(471,195)		(471,195)
10	Total Taxes Other Than Income Taxes		$ (663)	$ 4,689	$ (168,185)	$ 2,894	$ (471,290)		$ (632,555)
	Income Taxes								
11	To adjust book taxes							$ (212,800)	$ (212,800)

Test Year Ending June 30, 2018

			Total Company			Kansas Jurisdiction			
Line No.	Description	Reference	Total Company Ending Balance	Pro Forma Adjustments	Total Company Adjusted Ending Balance	Allocation Factor	Kansas Ending Balance	Pro Forma Adjustments	Kansas Adjusted Ending Balance
	(a)	(b)	(c)	(d)	(e) + (c) + (d)	(f)	(g) =(e)*(f)	(h)	(i) = (g) + (h)
1	Net Operating Income Before Income Taxes	Section 9	$ 192,399,012	$ (2,428,851)	$ 189,970,161	3.39%	$ 6,440,699	$ (2,428,851)	$ 4,011,848
2	Add:								-
3	Book Depreciation	WP-9 Operating Income	76,419,083	259,763	76,678,846	4.82%	3,699,247	259,601	3,958,848
4	Regulatory Amortization	WP-9 Operating Income	3,925,649		3,925,649	4.74%	186,023	162	186,185
5	Nondeductible Expenses (Meals)	DR 71 Response	131,939		131,939	3.35%	4,417		4,417
6	Non-deductible Club Dues	DR 71 Response	21,576		21,576	3.35%	722		722
7	Contributions in Aid of Construction	DR 71 Response	1,659,163		1,659,163	3.35%	55,542		55,542
8	Total Additions		82,157,410	259,763	82,417,173	4.79%	3,945,951	259,763	4,205,714
9	Less:								
10	Interest Expense	WP 11.4.1 Interest Sync	36,220,278		36,220,278	4.00%	1,449,493		1,449,493
11	Tax Depreciation	DR 71 Response	123,778,272		123,778,272	3.35%	4,143,569		4,143,569
12	Total Deductions		159,998,550	-	159,998,550	3.50%	5,593,063	-	5,593,063
13	Net Taxable Income		$ 114,557,872	$ (2,169,088)	$ 112,388,784	4.27%	$ 4,793,588	$ (2,169,088)	$ 2,624,500

			Test Year Ending June 30, 2018					
			Total Company			Kansas Jurisdiction		
Line No.	**Description**	**Reference**	**Adjusted Federal**	**Adjusted State**	**Total Taxes**	**Adjusted Federal**	**Adjusted State**	**Total Taxes**
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f)	(g)	(h) = (f) + (g)
1	Net Operating Income Before Income Taxes	**WP-11.2 Calc of Taxable Income Line 1**	$ 189,970,161	$ 189,970,161	$ 189,970,161	$ 4,011,848	$ 4,011,848	$ 8,023,697
2	Effective Tax Rates	**WP-11.4.2 GRCF Line 1 & 3**	19.67%	6.31%	25.99%	19.67%	6.31%	25.99%
3	Tax - Subtotal	**Line 1 x Line 2**	37,375,869	11,989,755	49,365,625	789,315	253,203	1,042,518
4	Interest Synchronization - Tax Impact	**WP-11.4.1 Interest Sync Line 4 & 5**	(7,126,195)	(2,286,003)	(9,412,197)	(285,182)	(91,483)	(376,665)
5	Taxes - Total	**Line 3 + Line 4**	30,249,674	9,703,753	39,953,427	504,133	161,720	665,853
6	Change in Deferred Taxes:	**WP-11a Taxes Detail Line 46**	64,540,050	-	64,540,050	1,948,086	-	1,948,086
7	Current Taxes	**Line 5 - Line 6**	(34,290,375)	9,703,753	(24,586,623)	(1,443,953)	161,720	(1,282,233)
8	Taxes - Total	**Line 6 + Line 7**	30,249,674	9,703,753	39,953,427	504,133	161,720	665,853
9	Excess ADIT Amortization	**WP 11-1**				(212,800)	-	(212,800)
10	Adjusted Taxes - Total		$ 30,249,674	$ 9,703,753	$ 39,953,427	$ 291,333	$ 161,720	$ 453,053

Test Year Ending June 30, 2018

		3%				4%				10%				Electric Advanced Coal Credit Iantan II				Total Company			
Line No.	Date	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance
	(a)	(b)	(c)	(d)	(e)=(b)-(c)+(d)	(f)	(g)	(h)	(i)=(f)-(g)+(h)	(j)	(k)	(l)	(m)=(j)-(k)+(l)	(n)	(o)	(p)	(q)=(n)-(o)+(p)	(r)	(s)	(t)	(u) = (e) + (i) + (m) + (q)
1	2005	$ 840	$ 202	$ -	$ 638	$ 54,849	$ 21,548		$ 33,301	$ 4,953,007	$ 515,900	$ -	$ 4,437,107				$ -	$ 5,008,696	$ 537,650	$ -	$ 4,471,046
2	2006	638	167		471	33,301	15,050		18,251	4,437,107	512,433	-	3,924,674	-			-	4,471,046	527,650	-	3,943,396
3	2007	471	133		338	18,251	12,918		5,333	3,924,674	514,599	-	3,410,075	-			-	3,943,396	527,650	-	3,415,746
4	2008	338	102		236	5,333	5,096		237	3,410,075	516,932	-	2,893,143	-			-	3,415,746	522,130	-	2,893,616
5	2009	236	81		155	237	226		11	2,893,143	501,251	-	2,391,892	-		17,712,500	17,712,500	2,893,616	501,558	17,712,500	20,104,558
6	2010	155	69		86	11			11	2,391,892	412,603	-	1,979,289	17,712,500		(112,714)	17,599,786	20,104,558	412,672	(112,714)	19,579,172
7	2011	86	59		27	11			11	1,979,289	368,932	-	1,610,357	17,599,786			17,599,786	19,579,172	368,991	-	19,210,181
8	2012	27	27		0	11			11	1,610,357	326,857	-	1,283,500	17,599,786			17,599,786	19,210,181	326,884	-	18,883,297
9	2013	0			0	11			11	1,283,500	234,156	-	1,049,344	17,599,786			17,599,786	18,883,297	234,156	-	18,649,141
10	2014	0			0	11			11	1,049,344	141,395	-	907,949	17,599,786			17,599,786	18,649,141	141,395	-	18,507,746
11	2015	0			0	11	11		-	907,949	141,239	-	766,710	17,599,786		112,714	17,712,500	18,507,746	141,250	112,714	18,479,210
12	2016	0			0	-			-	766,710	141,042	-	625,668	17,712,500	(266,778)		17,445,722	18,479,210	(125,736)	-	18,071,390
13	2017	0			0	-			-	625,668	141,239	-	484,429	17,445,722	200,084		17,245,638	18,071,390	341,323	-	17,730,067
14	6 months ended June 30, 2018	0			0	-			-	484,429	-	-	484,429	17,245,638			17,245,638	17,730,067	-	-	17,730,067
15	12 month ended June 30, 2017				-				-		142,177	-	767,845				17,445,722		-	-	18,071,390
16	12 month ended June 30, 2018				$ -				$ -		$ 86,295	$ -	$ 570,724				$ 17,245,638		$ -	$ -	$ 18,071,390

Test Year Ending June 30, 2018

		Ferc Account 190				Ferc Account 282				Ferc Account 283				Total Company			
Line No.	Date	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance	Beginning Balance	Annual Charges	Credit	Ending Balance
	(a)	(b)	(c)	(d)	(e)=(b)+(c)-(d)	(f)	(g)	(h)	(i)=(f)-(g)+(h)	(j)	(k)	(l)	(m)=(j)-(k)+(l)	(n)	(o)	(p)	(q)=(n)+(o)+(p)
1	2005	$ 21,158,500	$ 2,994,912	$ 6,220,229	$ 17,933,183	$ 115,450,686	$ 2,231,051	$ 9,334,086	$ 122,553,721	$ 38,402,499	$ (5,849,977)	$ (486,828)	$ 43,765,648	$ 175,011,685	$ (624,014)	$ 15,067,487	$ 184,252,552
2	2006	17,933,183	8,312,690	(15,517,732)	41,763,605	122,553,721	4,474,399	8,218,758	126,298,080	43,765,648	(7,521,008)	5,016,080	56,302,736	184,252,552	5,266,081	(2,282,894)	191,801,527
3	2007	41,763,605	5,442,278	8,559,089	38,646,794	126,298,080	3,812,770	21,335,817	143,821,127	56,302,736	2,344,941	6,857,066	60,814,861	224,364,421	11,599,989	36,751,972	199,212,438
4	2008	38,646,794	6,825,127	(25,680,227)	71,152,148	143,821,127	3,528,967	16,330,845	156,623,005	60,814,861	(23,613,237)	3,611,789	88,039,887	243,282,782	(13,259,143)	(5,737,593)	235,761,232
5	2009	71,152,148	9,573,924	(5,441,609)	86,167,681	156,623,005	6,802,819	29,688,200	179,508,386	88,039,887	(1,800,437)	11,134,288	100,974,612	315,815,040	14,576,306	35,380,879	295,010,467
6	2010	86,167,681	25,376,597	5,648,366	105,895,912	179,508,386	8,379,082	30,502,516	201,631,820	100,974,612	(8,101,711)	7,190,455	116,266,778	366,650,678	25,653,969	43,341,337	348,963,310
7	2011	105,895,912	16,035,656	27,652,712	94,278,856	201,631,820	9,142,627	46,201,163	238,690,355	116,266,778	4,727,097	7,982,191	119,521,872	423,794,510	29,905,380	81,836,065	371,863,824
8	2012	94,278,856	4,401,161	(988,294)	99,668,311	238,690,355	9,749,693	47,317,700	276,258,362	119,521,872	(366,553)	5,488,931	125,377,356	452,491,083	13,784,301	51,818,337	414,457,047
9	2013	99,668,311	16,967,331	50,454,117	66,181,525	276,258,362	8,675,896	26,044,625	293,627,091	125,377,356	30,470,661	1,913,293	96,819,988	501,304,029	56,113,888	78,412,035	479,005,882
10	2014	66,181,525	28,410,729	5,792,867	88,799,387	293,627,091	9,384,906	72,584,922	356,827,107	96,819,988	(9,244,049)	3,360,186	109,424,223	456,628,604	28,551,586	81,737,975	403,442,215
11	2015	112,499,387	21,333,585	43,837,181	89,995,791	356,827,107	11,677,411	31,165,945	376,315,641	113,924,224	6,215,712	2,513,291	110,221,803	583,250,718	39,226,708	77,516,417	544,961,009
12	2016	89,995,791	16,726,930	7,607,075	99,115,646	376,315,641	11,818,727	54,501,020	418,997,934	110,221,803	2,467,973	2,030,065	109,783,895	576,533,235	31,013,630	64,138,160	543,408,705
13	2017	99,115,646	(8,585,924)	(15,205,851)	105,735,573	418,997,934	23,556,049	(88,895,755)	306,546,130	109,783,895	14,166,001	(19,415,442)	76,202,452	627,897,475	29,136,126	(123,517,048)	780,550,649
14	6 Month Ended June 30, 2018	105,735,573	(527,626)	6,010,343	99,197,604	306,546,130	2,866,203	(11,894,473)	291,785,454	76,202,452	5,798,977	59,600	70,463,075	488,484,155	8,137,554	(5,824,530)	502,446,239
15	12 month ended June 30, 2017				116,419,399				450,880,173				109,142,410				676,441,982
16	12 month ended June 30, 2018				$ 92,823,367				$ 171,175,212				$ 36,852,538				$ 300,851,117

Basis of Allocation of Property and Expenses

Section 12, Schedule 2, shows in detail the basis of allocation for majority of the cost of service components included the test year end of June 30, 2018. The amounts are displayed by jurisdiction and at a total company level.

This allocation process is similar to past processes however there have been specific administrative and general expense allocators which have been updated since the last rate case. See the attached Section 12-AG Summary of Changes in Allocation Factors for the detailed list of which allocators have been updated since the last rate case.

In this process of allocation by states, there is an exception to the basic uniform procedure. The portions of the rate base components and net operating revenue components which relate to resale customers are allocated by procedures using different factors than those used for all other customers.

Three towns in Missouri and one town in Kansas are supplied by Empire at resale rates. Amounts of fixed generation property and expense and common transmission property and expense allocated to these resale transactions are assigned on the basis of coincident peak demands of these resale customers in relation to the total Company system demand. All other property and expense allocations to these four wholesale customers are made on the same uniform basis used for retail customers.

After deductions for property and expenses applicable to resale transactions, the remaining property and operating costs are then allocated on a uniform basis to all retail customers in each of the four states.

Variable production expenses are allocated on the basis of kilowatt-hour sales by jurisdiction. Fixed production expenses are allocated based on a twelve-month average coincident peak demand.

Twelve-month average coincident peak demands by states are used as the basis for allocation of the remaining property and expenses related to transmission facilities.

All distribution property and related expenses are allocated to states on the basis of actual physical location except those portions applicable to resale customers are assigned separately.

Customer accounts expenses are allocated to states on the basis of the number of average 12 Months of customers served.

Customer assistance expenses are allocated to states on the basis of the average number of customers and certain costs are assigned directly on basis of location.

Sales expenses are allocated on the basis of revenues by states.

Administrative and general expenses are allocated on the basis of labor cost distribution except for Electric Power Research Institute research and development costs, franchise requirements and regulatory commission expenses, which are assigned directly to jurisdiction of origin.

Depreciation expense is allocated by functional groups of property on the basis of depreciable electric plant in service by functional classes as allocated by states. The exception to this allocation method applies to the depreciation expense for Distribution property. The allocation method for Distribution property is based on direct expenses assigned by location.

Real and personal property taxes are allocated on the basis of electric plant in service as allocated, payroll taxes on the basis of labor cost, distribution expenses and other taxes by state of origin.

Income taxes are calculated on the basis of taxable income by states.

Prepayments are allocated on the basis of electric plant in service as allocated by states.

Fuel Inventory is allocated on the basis of a 12 month average kilowatt-hour sales.

Other materials and supplies related to generating plants are allocated on the same basis as allocated generation plant, with the remainder of materials and supplies on the basis of distribution property by states.

Deferred income tax and investment tax credit balances are allocated on the basis of total electric plant in service.

Customer deposits are directly assigned to state of origin.

The Empire District Electric Company
State of Kansas
Section 12-AG Summary of Changes in Allocation Factors
For the test year ending June 30, 2018

Allocation of Rate Base Item	Test Year Allocation Factor	Prior Rate Case Allocation Factor	Reason for proposed new allocation methodology
Other Electric Operating Revenues	12 Month Average Coincident Peak Demand Assigned Directly on basis of location	Assigned directly on basis of location	Due to Empire's entry into the SPP market and the creation of new accounts we had to reevaluate the allocation methodologies for certain Other Electric Operating Revenues.
Sales for Resale/Other	Total On-System Production Expense	No allocation factor assigned	This item was previously allocated by 12 month average coincidental peak demand. However, this line item was removed from the Income Statement in it's entirety and therefore has no impact on the current rate case preceding.
Customer Assistance Expense	Average Number of System Electric Customers Assigned directly on basis of location	Number of Electric Customers	Upon review of certain expenses it was determined that there may be items that need to be assigned to a specific jurisdiction versus number of electric customers.
Other Administrative & General Adjustments	A&G Labor Allocation	Subtotal of Electric Operating Expenses	To comply with FERC mandated guidelines.
Payroll Taxes	A&G Labor Allocation	Subtotal of Electric Operating Expenses	To comply with FERC mandated guidelines
Gain on Sale of Assets	Plant Subtotal (Production, Transmission & Distribution)	Assigned directly on basis of location	It was determined that some sale of assets may need to be allocated by another methodology versus directly. For instance if the asset sold impacted all jurisdictions versus just one (i.e., Unit Train). Therefore, Empire updated its allocation factor to better align with the specific asset sold.

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail				Total Retail	Resale - Municipalities		Total Company
			Missouri	Kansas	Arkansas	Oklahoma		Missouri	Kansas	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
Electric Utility Plant:										
1. Production Plant	28	WP - Plant in Service	$ 1,127,879,054	$ 63,473,131	$ 40,107,695	$ 35,787,669	$ 1,267,247,549	$ 68,734,304	$ 2,689,044	$ 1,338,670,897
Adjustments			-	-	-	-	-	-	-	-
Production Plant Adjusted			1,127,879,054	63,473,131	40,107,695	35,787,669	1,267,247,549	68,734,304	2,689,044	1,338,670,897
%			84.2536%	4.7415%	2.9961%	2.6734%	94.6646%	5.1345%	0.2009%	100.0000%
2. Transmission Plant	28	WP - Plant in Service	314,052,318	17,635,395	11,210,122	9,943,258	352,841,093	19,097,162	747,125	372,685,379
Adjustments			-	-	-	-	-	-	-	-
Transmission Plant Adjusted			314,052,318	17,635,395	11,210,122	9,943,258	352,841,093	19,097,162	747,125	372,685,379
%			84.2674%	4.7320%	3.0079%	2.6680%	94.6753%	5.1242%	0.2005%	100.0000%
3. Distribution Plant		WP - Plant in Service	861,114,151	53,570,620	26,131,723	30,877,251	971,693,744	2,371,730	113,304	974,178,778
Adjustments			-	-	-	-	-	-	-	-
Distribution Plant Adjusted			861,114,151	53,570,620	26,131,723	30,877,251	971,693,744	2,371,730	113,304	974,178,778
%			88.3939%	5.4991%	2.6824%	3.1696%	99.7449%	0.2435%	0.0116%	103.1696%
4. Production, Transmission & Distribution Plant Subtotal			2,303,045,523	134,679,146	77,449,539	76,608,178	2,591,782,386	90,203,195	3,549,473	2,685,535,054
Adjustments			-	-	-	-	-	-	-	-
Production, Transmission & Distribution Plant Adjusted			2,303,045,523	134,679,146	77,449,539	76,608,178	2,591,782,386	90,203,195	3,549,473	2,685,535,054
%			85.7574%	5.0150%	2.8840%	2.8526%	96.5090%	3.3589%	0.1322%	100.0000%
5. General Plant	4	WP - Plant in Service	76,737,767	4,487,526	2,580,628	2,552,594	86,358,516	3,005,582	118,269	89,482,366
Adjustments			-	-	-	-	-	-	-	-
General Plant Adjusted			76,737,767	4,487,526	2,580,628	2,552,594	86,358,516	3,005,582	118,269	89,482,366
%			85.7574%	5.0150%	2.8840%	2.8526%	96.5090%	3.3589%	0.1322%	100.0000%
6. Intangible Plant	4,69	WP - Plant in Service	37,179,100	2,174,186	1,250,303	1,236,720	41,840,309	1,456,191	57,301	43,353,801
Adjustments			-	-	-	-	-	-	-	-
Intangible Plant Adjusted			37,179,100	2,174,186	1,250,303	1,236,720	41,840,309	1,456,191	57,301	43,353,801
%			85.7574%	5.0150%	2.8840%	2.8526%	96.5090%	3.3589%	0.1322%	100.0000%
7. Total Electric Utility Plant (Includes property under capital lease)		WP - Plant in Service	2,416,962,390	141,340,858	81,280,470	80,397,492	2,719,981,211	94,664,968	3,725,043	2,818,371,221
Adjustments			-	-	-	-	-	-	-	-
Total Electric Utility Plant Adjusted			2,416,962,390	141,340,858	81,280,470	80,397,492	2,719,981,211	94,664,968	3,725,043	2,818,371,221
%			85.7574%	5.0150%	2.8840%	2.8526%	96.5090%	3.3589%	0.1322%	100.0000%
8. Electric Plant Held for Future Use	28	WP - Plant Held for Future Use	735,449	41,299	26,252	23,285	826,284	44,722	1,750	872,756
Electric Utility Depreciation Reserve:										
9. Production Reserve	28	WP - AD	258,036,601	14,423,019	9,207,674	8,132,043	289,799,338	15,618,517	611,032	306,028,887
Adjustments			-	-	-	-	-	-	-	-
Production Reserve Adjusted			258,036,601	14,423,019	9,207,674	8,132,043	289,799,338	15,618,517	611,032	306,028,887
10. Transmission Reserve	28	WP - AD	87,810,890	4,930,961	3,134,416	2,780,194	98,656,462	5,339,680	208,901	104,205,042
Adjustments			-	-	-	-	-	-	-	-
Transmission Reserve Adjusted			87,810,890	4,930,961	3,134,416	2,780,194	98,656,462	5,339,680	208,901	104,205,042
11. Distribution Reserve	29	WP - AD	389,794,071	24,267,353	11,784,544	14,036,852	439,882,820	1,073,359	50,923	441,007,102
Adjustments			-	-	-	-	-	-	-	-
Distribution Reserve Adjusted			389,794,071	24,267,353	11,784,544	14,036,852	439,882,820	1,073,359	50,923	441,007,102
12. General Reserve	4	WP - AD	44,134,996	2,580,958	1,484,224	1,468,100	49,668,278	1,728,632	68,021	51,464,931
Adjustments			-	-	-	-	-	-	-	-
General Reserve Adjusted			44,134,996	2,580,958	1,484,224	1,468,100	49,668,278	1,728,632	68,021	51,464,931
13. Amortization of Electric Plant	4	WP - AD	17,869,575	1,044,990	600,939	594,411	20,109,915	699,896	27,541	20,837,351
Adjustments			-	-	-	-	-	-	-	-
Amortization of Electric Plant Adjusted			17,869,575	1,044,990	600,939	594,411	20,109,915	699,896	27,541	20,837,351
14. Iatan 2 Regulatory Plan Amortization	68	WP - AD	37,312,953	-	-	-	37,312,953	-	-	37,312,953
Adjustments			-	-	-	-	-	-	-	-
Regulatory Plant Amortization Adjusted			37,312,953	-	-	-	37,312,953	-	-	37,312,953
15. Total Electric Utility Depreciation Reserve and Amortization		WP - AD	834,959,085	47,247,281	26,211,798	27,011,600	935,429,764	24,460,084	966,418	960,856,266
Adjustments			-	-	-	-	-	-	-	-
Total Electric Utility Depreciation Reserve and Amortization Adjusted			834,959,085	47,247,281	26,211,798	27,011,600	935,429,764	24,460,084	966,418	960,856,266

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail Missouri	Retail Kansas	Retail Arkansas	Retail Oklahoma	Total Retail	Resale - Municipalities Missouri	Resale - Municipalities Kansas	Total Company
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
16. Construction Work in Progress:										
Production	1									
Adjustments										
Production Adjusted										
Transmission	2									
Adjustments										
Transmission Adjusted										
Distribution	68									
Adjustments										
Distribution Adjusted										
General	5									
Adjustments										
General Adjusted										
Intangible	6									
Adjustments										
Intangible Adjusted										
Total Construction Work in Progress										
Adjustments										
Total Construction Work in Progress Adjusted										
17. Materials and Supplies - 13-Month Avg:										
Fuel	27	WP - Materials	17,311,062	946,388	713,950	633,900	19,605,300	1,344,848	42,600	20,992,748
Adjustments			-	-	-	-	-	-	-	-
Fuel Adjusted			17,311,062	946,388	713,950	633,900	19,605,300	1,344,848	42,600	20,992,748
Other Production Materials	1	WP - Materials	5,357,346	301,493	190,509	169,989	6,019,337	326,483	12,773	6,358,593
Adjustments			-	-	-	-	-	-	-	-
Other Production Materials Adjusted			5,357,346	301,493	190,509	169,989	6,019,337	326,483	12,773	6,358,593
Transmission & Distribution Materials	3	WP - Materials	22,091,451	1,374,327	670,396	792,140	24,928,314	60,846	2,907	24,992,067
Adjustments			-	-	-	-	-	-	-	-
Transmission & Distribution Materials Adjusted			22,091,451	1,374,327	670,396	792,140	24,928,314	60,846	2,907	24,992,067
Clearing Account Materials	7	WP - Materials	239,588	14,011	8,057	7,970	269,626	9,384	369	279,379
Adjustments			-	-	-	-	-	-	-	-
Clearing Account Materials Adjusted			239,588	14,011	8,057	7,970	269,626	9,384	369	279,379
Total Materials and Supplies - 13 Month Average		WP - Materials	44,999,447	2,636,219	1,582,912	1,603,999	50,822,577	1,741,561	58,648	52,622,787
Adjustments			-	-	-	-	-	-	-	-
Total Materials and Supplies Adjusted			44,999,447	2,636,219	1,582,912	1,603,999	50,822,577	1,741,561	58,648	52,622,787
18. Prepayments - 13-Month Average	7	WP - Prepayments	7,687,612	449,562	258,528	255,720	8,651,422	301,100	11,848	8,964,370
Adjustments			-	-	-	-	-	-	-	-
Prepayments Adjusted			7,687,612	449,562	258,528	255,720	8,651,422	301,100	11,848	8,964,370
19. Cash Working Capital	68		-	-	-	-	-	-	-	-
20. Accumulated Deferred Income Taxes		WP - ADIT	(238,207,781)	(14,308,436)	(7,896,514)	(7,999,626)	(268,412,357)	(9,179,332)	(361,204)	(277,952,894)
21. Regulatory Assets		WP - Regulatory Assets	137,533,863	4,392,537	3,147,768	3,286,575	148,360,744	4,739,333	171,808	153,271,885
22. Regulatory Liabilities		WP - Regulatory Liabilities	(148,229,042)	(8,510,504)	(4,903,046)	(4,163,282)	(165,805,874)	(6,551,377)	(248,551)	(172,605,803)
Investment Tax Credit:										
23. Prior 1971 Additions	7	WP - ITC	1	0	0	0	1	0	0	1
24. Customer Deposits - 13 Month Avg	68	WP - Customer Deposits	12,626,645	436,996	325,567	463,969	13,853,176	-	-	13,853,176
25. Customer Advances - 13 Month Avg	68	WP - Customer Advances	2,709,906	16,333	9,907	40,262	2,776,408	-	-	2,776,408
26. Interest on Customer Deposits (12 Months)		WP - Customer Deposits	695,811	7,062	981	10,019	713,873	-	-	713,873

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail: Missouri	Retail: Kansas	Retail: Arkansas	Retail: Oklahoma	Total Retail	Resale - Municipalities: Missouri	Resale - Municipalities: Kansas	Total Company
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
27. Kilowatt-Hour Sales - 12 Months Ended										6,624,289,115
Less SPP Integrated Market (see note at bottom of worksheet)		(1)								1,492,641,360
System Kilowatt-Hour Sales	68	WP - KWH Sales Allocator	4,231,664,720	231,343,327	174,523,994	154,956,049	4,792,488,090	328,746,261	10,413,404	5,131,647,755
%			82.4621%	4.5082%	3.4009%	3.0196%	93.3908%	6.4063%	0.2029%	100.0000%
28. Coincident Peak Demand - 12 Month Avg	68	WP - Peak Allocator	805,667	45,242	28,758	25,508	905,175	48,992	1,917	956,083
%			84.2674%	4.7320%	3.0079%	2.6680%	94.6753%	5.1242%	0.2005%	100.0000%
Depreciable Distribution Plant:										
29. Total Distribution Plant	68	WP - Depreciable Plant Allocator	861,114,151	53,570,620	26,131,723	30,877,251	971,693,744	2,371,730	113,304	974,178,778
Less Nondepreciable Distribution Plant			4,154,920	218,081	223,031	16,791	4,612,823	11,916	1,347	4,626,086
Depreciable Distribution Plant			856,959,231	53,352,538	25,908,692	30,860,460	967,080,921	2,359,814	111,957	969,552,692
%			88.3871%	5.5028%	2.6722%	3.1830%	99.7451%	0.2434%	0.0115%	100.0000%
Electric Operating Revenues:										
30. Residential	68	WP - Revenues	243,392,455	12,431,473	5,510,648	5,177,390	266,511,967	-	-	266,511,967
Adjustments			-	-	-	-	-	-	-	-
Residential Adjusted			243,392,455	12,431,473	5,510,648	5,177,390	266,511,967	-	-	266,511,967
31. Commercial	68	WP - Revenues	171,190,455	6,176,544	3,307,159	5,180,105	185,854,262	-	-	185,854,262
Adjustments			-	-	-	-	-	-	-	-
Commercial Adjusted			171,190,455	6,176,544	3,307,159	5,180,105	185,854,262	-	-	185,854,262
32. Industrial	68	WP - Revenues	78,563,445	5,278,289	6,927,017	3,231,009	93,999,760	-	-	93,999,760
Adjustments			-	-	-	-	-	-	-	-
Industrial Adjusted			78,563,445	5,278,289	6,927,017	3,231,009	93,999,760	-	-	93,999,760
33. Public Street & Hwy Lighting	68	WP - Revenues	3,831,673	261,544	77,616	86,712	4,257,545	-	-	4,257,545
Adjustments			-	-	-	-	-	-	-	-
Public Street & Hwy Lighting Adjusted			3,831,673	261,544	77,616	86,712	4,257,545	-	-	4,257,545
34. Other Public Authorities	68	WP - Revenues	10,651,299	481,944	437,994	222,499	11,793,735	-	-	11,793,735
Adjustments			-	-	-	-	-	-	-	-
Other Public Authorities Adjusted			10,651,299	481,944	437,994	222,499	11,793,735	-	-	11,793,735
35. Interdepartmental	68	WP - Revenues	304,807	30,824	-	-	335,631	-	-	335,631
Adjustments			-	-	-	-	-	-	-	-
Interdepartmental Adjusted			304,807	30,824	-	-	335,631	-	-	335,631
36. For Resale-Municipalities	68	WP - Revenues	-	-	-	-	-	19,297,267	823,058	20,120,325
37. Total On-System Revenue from the Sale of Electricity	68	WP - Revenues	507,934,134	24,660,618	16,260,433	13,897,714	562,752,900	19,297,267	823,058	582,873,225
Adjustments			-	-	-	-	-	-	-	-
Total On-System Revenue from Sale of Electricty Adjusted			507,934,134	24,660,618	16,260,433	13,897,714	562,752,900	19,297,267	823,058	582,873,225
38. Other Revenues	28,68	WP - Revenues	9,542,830	(56,921)	91,350	283,940	9,861,199	2,444,232	197,040	12,502,471
39. Total On-System Electric Revenues		WP - Revenues	517,476,964	24,603,697	16,351,783	14,181,655	572,614,098	21,741,499	1,020,098	595,375,695
Adjustments			-	-	-	-	-	-	-	-
Total On-System Electric Revenues Adjusted			517,476,964	24,603,697	16,351,783	14,181,655	572,614,098	21,741,499	1,020,098	595,375,695
%			86.9160%	4.1325%	2.7465%	2.3820%	96.1769%	3.6517%	0.1713%	100.0000%
40. For Resale - SPP Integrated Market	42c	WP - Revenues	29,618,747	1,507,495	1,261,516	1,120,736	33,508,494	2,333,488	77,268	35,919,250
Adjustments			-	-	-	-	-	-	-	-
Sales for Resale/Other Adjusted			29,618,747	1,507,495	1,261,516	1,120,736	33,508,494	2,333,488	77,268	35,919,250
41. Total Electric Operating Revenues		WP - Revenues	547,095,711	26,111,192	17,613,299	15,302,391	606,122,592	24,074,987	1,097,366	631,294,945
Adjustments			-	-	-	-	-	-	-	-
Total Electric Operating Revenues Adjusted			547,095,711	26,111,192	17,613,299	15,302,391	606,122,592	24,074,987	1,097,366	631,294,945
Electric Operating Expenses:										
42. Production Expense:										
Off-System Wholesale	27,28	WP - Expenses	-	-	-	-	-	-	-	-
Adjustments			-	-	-	-	-	-	-	-
Off-System Wholesale Adjusted			-	-	-	-	-	-	-	-

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail				Total Retail	Resale - Municipalities		Total Company
			Missouri	Kansas	Arkansas	Oklahoma		Missouri	Kansas	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
a. Variable Production Expense	27	WP - Expenses	131,303,458	6,281,132	5,737,366	5,099,252	148,421,208	10,834,929	343,208	159,599,345
Adjustments			-	-	-	-	-	-	-	-
Variable Production Expense Adjusted			131,303,458	6,281,132	5,737,366	5,099,252	148,421,208	10,834,929	343,208	159,599,345
b. Fixed Production Expense	28	WP - Expenses	39,096,697	2,391,664	1,520,286	1,348,477	44,357,125	2,589,905	101,323	47,048,353
Adjustments			-	-	-	-	-	-	-	-
Fixed Production Expense Adjusted			39,096,697	2,391,664	1,520,286	1,348,477	44,357,125	2,589,905	101,323	47,048,353
c. Total On-System Production Expense		WP - Expenses	170,400,155	8,672,796	7,257,652	6,447,730	192,778,333	13,424,834	444,531	206,647,698
Adjustments			-	-	-	-	-	-	-	-
Total On-System Production Expense Adjusted			170,400,155	8,672,796	7,257,652	6,447,730	192,778,333	13,424,834	444,531	206,647,698
43. Transmission Expense	2	WP - Expenses	21,863,533	1,224,251	778,208	690,262	24,556,255	500,094	19,565	25,075,914
Adjustments			-	-	-	-	-	-	-	-
Transmission Expense Adjusted			21,863,533	1,224,251	778,208	690,262	24,556,255	500,094	19,565	25,075,914
44. Distribution Expense	3	WP - Expenses	22,422,074	1,499,028	666,503	787,541	25,375,146	60,492	2,890	25,438,528
Adjustments			-	-	-	-	-	-	-	-
Distribution Expense Adjusted			22,422,074	1,499,028	666,503	787,541	25,375,146	60,492	2,890	25,438,528
45. Customer Accounts Expense	66	WP - Expenses	7,792,693	490,707	232,932	237,787	8,754,118	152	51	8,754,321
Adjustments			-	-	-	-	-	-	-	-
Customer Accounts Expense Adjusted			7,792,693	490,707	232,932	237,787	8,754,118	152	51	8,754,321
46. Customer Assistance Expense	66,68	WP - Expenses	3,821,740	87,232	78,114	42,369	4,029,455	86,026	28,675	4,144,157
Adjustments			-	-	-	-	-	-	-	-
Customer Assistance Expense Adjusted			3,821,740	87,232	78,114	42,369	4,029,455	86,026	28,675	4,144,157
47. Sales Expense	39	WP - Expenses	138,918	6,605	4,390	3,807	153,719	-	-	153,719
Adjustments			-	-	-	-	-	-	-	-
Sales Expense Adjusted			138,918	6,605	4,390	3,807	153,719	-	-	153,719
48. Subtotal			226,439,112	11,980,618	9,017,800	8,209,496	255,647,026	14,071,599	495,712	270,214,337
Less Off-System Wholesale			-	-	-	-	-	-	-	-
System Subtotal			226,439,112	11,980,618	9,017,800	8,209,496	255,647,026	14,071,599	495,712	270,214,337
Adjustments			-	-	-	-	-	-	-	-
System Subtotal Adjusted			226,439,112	11,980,618	9,017,800	8,209,496	255,647,026	14,071,599	495,712	270,214,337
%			83.7998%	4.4337%	3.3373%	3.0381%	94.6090%	5.2076%	0.1835%	100.0000%
49. Administrative and General Expenses:										
a. Research and Development	48	WP - Expenses	-	-	-	-	-	-	-	-
Adjustments			-	-	-	-	-	-	-	-
Research and Development Adjusted			-	-	-	-	-	-	-	-
b. Franchise Requirements	68		-	-	-	-	-	-	-	-
Adjustments			-	-	-	-	-	-	-	-
Franchise Requirements Adjusted			-	-	-	-	-	-	-	-
c. Regulatory Commission	68	WP - Expenses	1,041,728	103,350	31,383	13,862	1,190,322	124,567	6,556	1,321,445
Adjustments			-	-	-	-	-	-	-	-
Regulatory Commission Adjusted			1,041,728	103,350	31,383	13,862	1,190,322	124,567	6,556	1,321,445
d. Other Administrative & General	Lbr	WP - Expenses	41,728,659	2,072,638	1,612,165	1,539,467	46,952,929	1,866,523	80,029	48,899,482
Adjustments			-	-	-	-	-	-	-	-
Other Administrative & General Adjusted			41,728,659	2,072,638	1,612,165	1,539,467	46,952,929	1,866,523	80,029	48,899,482
e. Total Administrative & General Expense			42,770,387	2,175,988	1,643,548	1,553,329	48,143,252	1,991,090	86,585	50,220,927
Adjustments			-	-	-	-	-	-	-	-
Total Administrative & General Adjusted			42,770,387	2,175,988	1,643,548	1,553,329	48,143,252	1,991,090	86,585	50,220,927
50. Total System Electric Operating Expense			269,209,499	14,156,606	10,661,348	9,762,825	303,790,278	16,062,689	582,297	320,435,264
Adjustments			-	-	-	-	-	-	-	-
System Electric Operating Expense Adjusted			269,209,499	14,156,606	10,661,348	9,762,825	303,790,278	16,062,689	582,297	320,435,264
Plus Off-System Wholesale			-	-	-	-	-	-	-	-
Total Adjusted System Electric Operating Expense			269,209,499	14,156,606	10,661,348	9,762,825	303,790,278	16,062,689	582,297	320,435,264

Depreciation and Amortization Expense:

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail Missouri	Retail Kansas	Retail Arkansas	Retail Oklahoma	Total Retail	Resale - Municipalities Missouri	Resale - Municipalities Kansas	Total Company
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
51. Production	1	(2)	30,407,006	1,274,608	1,045,385	694,360	33,421,360	1,502,898	55,328	34,979,586
Adjustments			-	-	-	-	-	-	-	-
Production Adjusted			30,407,006	1,274,608	1,045,385	694,360	33,421,360	1,502,898	55,328	34,979,586
52. Transmission	2	(2)	6,425,968	413,149	176,360	225,107	7,240,584	443,155	16,327	7,700,066
Adjustments			-	-	-	-	-	-	-	-
Transmission Adjusted			6,425,968	413,149	176,360	225,107	7,240,584	443,155	16,327	7,700,066
53. Distribution	3	(2)	27,309,223	1,858,526	537,225	961,250	30,666,223	60,663	2,897	30,729,784
Adjustments			-	-	-	-	-	-	-	-
Distribution Adjusted			27,309,223	1,858,526	537,225	961,250	30,666,223	60,663	2,897	30,729,784
54. General	5	(2)	2,598,135	152,963	67,269	81,656	2,900,023	105,704	3,920	3,009,647
Adjustments			-	-	-	-	-	-	-	-
General Adjusted			2,598,135	152,963	67,269	81,656	2,900,023	105,704	3,920	3,009,647
55. Total Depreciation		(2)	66,740,332	3,699,247	1,826,239	1,962,373	74,228,191	2,112,420	78,473	76,419,083
Adjustments			-	-	-	-	-	-	-	-
Total Depreciation Adjusted			66,740,332	3,699,247	1,826,239	1,962,373	74,228,191	2,112,420	78,473	76,419,083
56. Amortization of Electric Plant	4	WP - Amortization Expense	3,397,343	186,023	106,976	105,814	3,796,155	124,591	4,903	3,925,649
Adjustments			-	-	-	-	-	-	-	-
Amortization of Electric Plant Adjusted			3,397,343	186,023	106,976	105,814	3,796,155	124,591	4,903	3,925,649
57. Regulatory Plan Amortization	68		-	-	-	-	-	-	-	-
Adjustments			-	-	-	-	-	-	-	-
Amortization of Electric Plant Adjusted			-	-	-	-	-	-	-	-
58. Total Depreciation/Amortization Expense			70,137,675	3,885,270	1,933,215	2,068,186	78,024,346	2,237,011	83,376	80,344,732
Adjustments			-	-	-	-	-	-	-	-
Total Depreciation/Amortization Expense Adjusted			70,137,675	3,885,270	1,933,215	2,068,186	78,024,346	2,237,011	83,376	80,344,732
59. Taxes Other Than Income Taxes:										
a. Property Taxes	7	WP - Taxes Other than Income Taxes	19,196,046	1,122,560	645,547	638,535	21,602,688	751,850	29,585	22,384,123
Adjustments			-	-	-	-	-	-	-	-
Property Taxes Adjusted			19,196,046	1,122,560	645,547	638,535	21,602,688	751,850	29,585	22,384,123
b. Payroll Taxes	Lbr	WP - Taxes Other than Income Taxes	2,962,308	147,203	114,774	109,598	3,333,883	132,882	5,697	3,472,463
Adjustments			-	-	-	-	-	-	-	-
Payroll Taxes Adjusted			2,962,308	147,203	114,774	109,598	3,333,883	132,882	5,697	3,472,463
c. Other Taxes	68	WP - Taxes Other than Income Taxes	9,764,223	471,290	216,512	160,933	10,612,958	-	-	10,612,958
Adjustments			-	-	-	-	-	-	-	-
Other Taxes Adjusted			9,764,223	471,290	216,512	160,933	10,612,958	-	-	10,612,958
Total Taxes Other Than Income Taxes			31,922,578	1,741,052	976,833	909,065	35,549,529	884,732	35,283	36,469,544
Adjustments			-	-	-	-	-	-	-	-
Total Taxes Other Than Income Taxes Adjusted			31,922,578	1,741,052	976,833	909,065	35,549,529	884,732	35,283	36,469,544
60. Merger Related Expenses	Lbr	WP - Merger Expenses	203,675	10,121	7,891	7,535	229,222	9,136	392	238,751
Adjustments			-	-	-	-	-	-	-	-
Merger Related Expenses Adjusted			203,675	10,121	7,891	7,535	229,222	9,136	392	238,751
61. Gain on Sale of Assets	4	WP - Gain on Sale of Assets	-	-	-	-	-	-	-	-
Adjustments			-	-	-	-	-	-	-	-
Reverse Gain on Sale of Assets Adjusted			-	-	-	-	-	-	-	-
62. Net Elec Operating Income Before Income Tax			175,622,284	6,318,142	4,034,012	2,554,779	188,529,218	4,881,419	396,018	193,806,655
Percentage			90.62%	3.26%	2.08%	1.32%	97.28%	2.52%	0.20%	100.00%
Less For Resale-SPP Integrated Market			29,618,747	1,507,495	1,261,516	1,120,736	33,508,494	2,333,488	77,268	35,919,250
System Net Electric Operating Income			146,003,538	4,810,648	2,772,496	1,434,042	155,020,724	2,547,931	318,750	157,887,405
Adjustments			-	-	-	-	-	-	-	-
Net On-System Electric Operating Income Before Income Tax Adjusted			146,003,538	4,810,648	2,772,496	1,434,042	155,020,724	2,547,931	318,750	157,887,405
Percentage			92.47%	3.05%	1.76%	0.91%	98.18%	1.61%	0.20%	100.00%
63. State Income Taxes	62	WP - Income Taxes	5,221,457	187,846	119,936	75,957	5,605,196	145,130	11,774	5,762,100
Less For Resale-SPP Integrated Market			880,600	44,820	37,506	33,321	996,247	69,377	2,297	1,067,922
System State Income Taxes			4,340,857	143,026	82,430	42,636	4,608,949	75,753	9,477	4,694,179

12 Months Ending June 30, 2018

Description	Allocation Reference	Workpaper Reference	Retail Missouri	Retail Kansas	Retail Arkansas	Retail Oklahoma	Total Retail	Resale - Municipalities Missouri	Resale - Municipalities Kansas	Total Company
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (d) + (e) + (f) + (g)	(i)	(j)	(k) = (h) + (i) + (j)
Adjustments			-	-	-	-	-	-	-	-
System State Income Taxes Adjusted			4,340,857	143,026	82,430	42,636	4,608,949	75,753	9,477	4,694,179
64. Federal Income Taxes	62	WP - Income Taxes	54,196,520	1,749,342	995,999	500,636	57,442,496	878,880	116,612	58,437,989
Less For Resale-SPP Integrated Market			(919,367)	(46,793)	(39,158)	(34,788)	(1,040,105)	(72,432)	(2,398)	(1,114,935)
System Federal Income Taxes			55,115,887	1,796,134	1,035,157	535,423	58,482,601	951,312	119,011	59,552,924
Adjustments			-	-	-	-	-	-	-	-
System Federal Income Taxes Adjusted			55,115,887	1,796,134	1,035,157	535,423	58,482,601	951,312	119,011	59,552,924
65. Net Electric Operating Income (see Note)			116,204,307	4,380,955	2,918,077	1,978,187	125,481,526	3,857,408	267,632	129,606,566
Less For Resale-SPP Integrated Market			29,657,513	1,509,468	1,263,167	1,122,203	33,552,352	2,336,542	77,369.05	35,966,263
System Net Electric Operating Income			86,546,794	2,871,487	1,654,909	855,983	91,929,174	1,520,866	190,263	93,640,303
Adjustments			-	-	-	-	-	-	-	-
System Net Electic Operating Income Adjusted			86,546,794	2,871,487	1,654,909	855,983	91,929,174	1,520,866	190,263	93,640,303

Note: Net Electric Operating Income does not reflect a $11 gain on the disposition of emission allowances (Account 411800) which has been recognized for internal financial reporting purposes.

Description	Allocation Reference	Workpaper Reference	Retail Missouri	Retail Kansas	Retail Arkansas	Retail Oklahoma	Total Retail	Resale - Municipalities Missouri	Resale - Municipalities Kansas	Total Company
66. Average Number of System Electric Customers	68		153,541	9,669	4,590	4,685	172,484	3	1	172,488
67. For Resale-SPP Integrated Market										
Revenues	28		29,618,747	1,507,495	1,261,516	1,120,736	33,508,494	2,333,488	77,268	35,919,250
Operating Expenses	28		-	-	-	-	-	-	-	-
Income Taxes	62		(38,767)	(1,973)	(1,651)	(1,467)	(43,858)	(3,054)	(101)	(47,013)
Net Operating Income			29,657,513	1,509,468	1,263,167	1,122,203	33,552,352	2,336,542	77,369	35,966,263

68. Assigned directly on basis of location

69. Intangible plant allocated to wholesale pertains to Stockton Line

Footnotes:
(1) - SPP Integrated Market balance is pulled from the Schedule 1 report found in the finance share drive: Finance / Financial Reporting - Corp / Financial Statements / Month / Sch 1.
Take the opposites of Sales to IM (cell G64) less SPP Financial/Actual Market Adjustment (cell G65).
(2) - Due to the complexity of the depreciation schedule, it is saved in its own workbook which can be found on the 4-state reguatory drive.

SECTION 13
SCHEDULE 1

Algonquin Power & Utilities Corp.

ANNUAL REPORT 2017

BUILDING A STRONG FOUNDATION FROM WHICH TO DELIVER SHAREHOLDER VALUE

Algonquin Power & Utilities Corp. ("APUC") owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets with a total value exceeding $10 billion.

APUC's operations are organized across two primary North American business units.

- **Liberty Power** owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets with a total capacity of approximately 1,545 MW.
- **Liberty Utilities** owns and operates a portfolio of U.S. - based regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations which collectively serve the needs of approximately 762,000 customers.

APUC is also **active in International Infrastructure Development and Operations** through its newly-formed joint venture - Abengoa Algonquin Global Energy Solutions (AAGES) and its 25% equity interest in Atlantica Yield plc (NASDAQ:AY).

APUC has developed an unparalleled portfolio of conservative building blocks with which to grow its earnings and cash flows and support share price appreciation and a growing dividend.

ALGONQUIN
Power & Utilities Corp.

AlgonquinPowerandUtilities.com **TSX/NYSE: AQN**

Cover image: Liberty Utilities' 50 MW Luning Facility, commissioned in Q1 2017

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FORWARD-LOOKING INFORMATION

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to: expected future growth and results of operations; ongoing and planned acquisitions, projects and initiatives, expectations regarding international developments and operations; and expectations regarding the future growth and results of operations of Atlantica Yield plc. Readers are advised that all forward-looking information in this document is provided subject to the cautionary statement regarding forward-looking information, which is found in management's discussion and analysis section of this Annual Report beginning at page 1.

LIBERTY UTILITIES

Transformational Growth in 2017

APUC's Liberty Utilities business group is its rate-regulated generation, transmission and distribution utility which provides electricity, natural gas, and water utility services to a total of approximately 762,000 customers in 12 U.S. states. APUC experienced transformational growth across it utility operating modalities in 2017, much of which can be attributed to the acquisition of The Empire District Electric Company ("Empire"). Marking a first for APUC, our utility rate base now includes power generating capacity. A total of nine power generating facilities were added to Liberty Utilities' portfolio of rate-based assets in 2017, including approximately 1,400 MW of generating capacity sourced from the Empire acquisition and another 50 MW of newly-commissioned solar generating capacity within Liberty Utilities' western region.

Liberty Utilities is committed to reducing customer costs through increased efficiencies and a prudent increase in the amount of renewable energy within the electricity mix delivered to customers. The expanded transmission businesses now include 1,200 miles of electrical transmission lines and 100 miles of natural gas transmission pipelines. Liberty Utilities is focused on delivering increased efficiencies to customers through continued investment in its utility systems.

APUC seeks to maximize total shareholder value through growth in earnings and cash flows to support share price appreciation and a growing dividend.

Total Customers (Total Connections)	2017	2016	Y/Y Growth
Electricity	265,000	94,000	182%
Natural Gas	337,000	293,000	15%
Water and Wastewater[1]	160,000	178,000	-10%
Total	**762,000**	**565,000**	**35%**

[1] Reduction reflects the disposition of Mountain Water Company in 2017.

UTILITY GROWTH CONTINUES

Seamless Integration, Strong Performance

On January 1, 2017, APUC completed the acquisition of Empire, a rate-regulated water, gas and electric utility serving approximately 221,000 customers in Missouri, Arkansas, Oklahoma, and Kansas. APUC's core utility operations have expanded materially - today, approximately 1,850 Liberty Utilities employees are dedicated to reliably meeting the needs of our electricity, natural gas, and water utility customers in 12 U.S. states. We were pleased that the integration of Empire's employees and operations was highly successful, and that Empire's contributions to our financial results were aligned with our expectations.

LIBERTY POWER

2017 Strength and Stability

APUC's Liberty Power business group generates and sells electricity produced by its diversified portfolio of North American renewable and clean power generation facilities. Liberty Power's portfolio of non-regulated generation facilities includes approximately 1,545 MW of hydroelectric, wind, solar, and thermal generating capacity, delivering renewable and clean energy under long term off-take agreements. Active across six Canadian provinces and eight U.S. states, Liberty Power delivers increasing shareholder value through the development of new greenfield power generation projects and the efficient operation of its extensive fleet of operational power facilities.

During 2017, our power development team successfully added a total of 160 MW of new renewable energy capacity to our portfolio, including our 150 MW Deerfield Wind Facility in Michigan and our 10 MW Bakersfield II Solar Facility in California.

APUC is dedicated to maintaining strong access to the capital necessary to build its business. In 2017, APUC successfully raised a combined total of approximately $2.5 billion to fund its strategic growth initiatives.

INTERNATIONAL DEVELOPMENT PLATFORM

On November 1, 2017, APUC announced that it had entered into agreements to create a new joint venture, Abengoa Algonquin Global Energy Solutions ("AAGES"), and to concurrently purchase a 25% equity interest in Atlantica Yield plc ("Atlantica" – NASDAQ:AY). Collectively these transactions represent APUC's important first steps into the international infrastructure development arena. We announced the successful completion of these transactions on March 9, 2018.

Accessing New International Infrastructure Opportunities through AAGES

AAGES provides a unique and risk-managed opportunity for APUC to pursue international infrastructure development while working alongside a proven, experienced partner. APUC has gained access to a curated collection of international development opportunities. Our partner in the joint venture, Seville, Spain-based Abengoa, S.A. ("Abengoa") has a 70-year track record of providing engineering and construction activities to a global client base. AAGES represents an important new component of our growth strategy, one which we believe will create enduring long-term value for our shareholders.

Atlantica Investment - Diverse, High Quality Portfolio

Atlantica owns and operates a diverse, long-term contracted portfolio of 22 facilities representing 1.7 GW of clean power generating capacity, 1,770 kilometers of electric transmission lines, and two desalination plants in selected global markets including North America, South America and EMEA. Atlantica's portfolio is complementary to APUC's existing operations, and APUC's commitment to Atlantica is expected to strengthen Atlantica's prospects through the addition of new assets, thereby accelerating the growth of its cash available for distribution.

Concentrating Solar facility. Photo courtesy of Atlantica.

2017 FINANCIAL ACHIEVEMENTS

APUC is led by an experienced executive management team that has a long-term track record of successfully growing the business. In 2017, APUC achieved:

85% Growth in adjusted EBITDA

81% Growth in adjusted net earnings

72% Growth in adjusted funds from operations

11% Increase in dividend per share

30% Increase in adjusted net earnings per share

26% Annual total shareholder return

2017 FINANCIAL HIGHLIGHTS

(in C$ millions)

Revenue	2017	2016	2015
Generation Revenue	282.6	243.1	222.6
Distribution Revenue	1,664.3	815.5	766.3
Other	30.9	37.4	39.0
Total Revenue	**1,977.8**	**1,096.0**	**1,027.9**
Adjusted EBITDA[1]	**883.4**	**476.9**	**375.4**
Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations[1]	614.5	356.4	287.4
Adjusted Net Earnings[1]	292.1	161.6	121.5
Per Share	0.74	0.57	0.46
Dividends to Shareholders	242.5	149.2	124.8
Per Share	0.61	0.55	0.49
Balance Sheet Data			
Total Assets	10,533.6	8,249.5	4,991.7
Long Term Debt (incl. current portion & convertible debentures)	3,864.5	4,272.0	1,486.8
Number of Shares outstanding as of Dec. 31	431,765,935	274,087,018	255,869,419
Renewable energy production (% of long term average)	**98%**	**94%**	**93%**
Utility Connections	**762,000**	**565,00**	**489,000**

[1] **Non-GAAP Financial Measures**
The terms "adjusted EBITDA", "adjusted net earnings", "adjusted net earnings per share", and "adjusted funds from operations" (together, the "Financial Measures") are used throughout this Annual Report. The Financial Measures are not recognized measures under generally accepted accounting principles in the United States. There is no standardized measure of the Financial Measures, consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A further discussion, calculation and analysis of these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.

OUR COMMITMENT TO ENTERPRISE RISK MANAGEMENT AND SUSTAINABILITY

Effective Risk Management – A Key to our Success

We are committed to continuous improvement of our risk management systems to address the changing dynamics of our business and our markets. In 2017, a new Risk Committee within our Board of Directors was established to provide additional oversight to our Enterprise Risk Management program. APUC-wide training remains an important means through which to ensure risks continue to be identified, analyzed and mitigated to optimize the likelihood of favorable business outcomes.

Safety is Embedded in our Culture

Safety remains a core component of APUC's culture, and we continue to refine the systems and programs that ensure the safety of our employees, our customers, and the communities in which we operate. APUC's enduring safety commitment is embodied in its "Drive to Zero" program and its goal to operate the businesses with zero lost time injuries and illnesses. APUC is reaping the tangible benefits of our commitment to safety across the organization – a prime example is the achievement of zero lost time injuries within the Liberty Power business group since 2015.

Dedication to Sustainable Practices

APUC continued to promote responsible and sustainable business practices throughout our operations in 2017. To strengthen our environmental measurement and management practices, APUC's environmental team commenced the implementation of an enterprise-wide Environmental Management System which will serve as the cornerstone of our efforts to achieve industry-leading environmental performance and management. 2017 also marked APUC's 10th consecutive year of reporting under the Carbon Disclosure Project.

AQN BY THE NUMBERS

25 PROVINCES AND STATES

762,000 UTILITY CUSTOMERS

2,241 EMPLOYEES

2,969 MW INSTALLED ELECTRIC GENERATING CAPACITY[1]

15 YEAR AVERAGE CONTRACT LENGTH OF POWER PURCHASE AGREEMENTS

12,629 KM OF GAS DISTRIBUTION LINES

59 HYDROELECTRIC GENERATORS

20,827 KM OF ELECTRICITY DISTRIBUTION LINES

463,236 SOLAR PANELS

3,890 KM OF WATER DISTRIBUTION MAINS

713 WIND TURBINES

[1] Includes 1,424 net MW of rate-base generation within Liberty Utilities

2017 LETTER TO SHAREHOLDERS

DEAR FELLOW SHAREHOLDERS,

For Algonquin Power and Utilities Corp., 2017 represented another remarkable year; transformational growth in our North American utilities operations, completion of new renewable energy generating facilities and the unveiling of our strategy for international expansion, all while delivering record financial results.

Our strong financial performance in 2017 can be traced to continued successful execution on our growth strategies, including the acquisition of The Empire District Electric Company. We achieved a number of important milestones in 2017: our asset base has now crested $10 billion and we completed our first investment outside of North America. From this expanded platform, we remain focused on the continued delivery of industry leading growth and value creation for our shareholders.

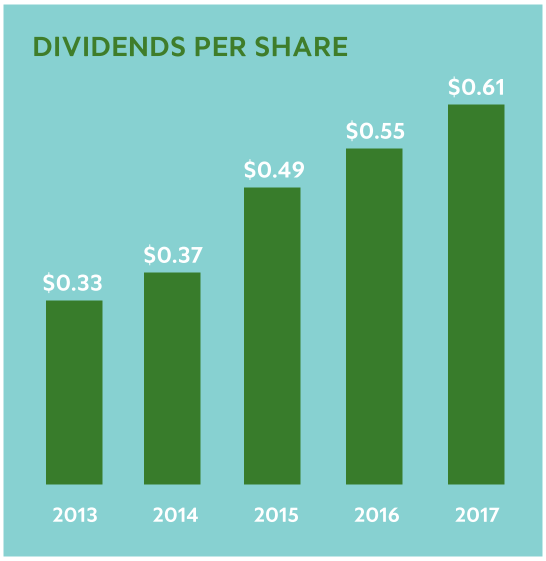
As always, our success can be directly attributed to our dedicated and growing team of power and utility professionals. As our organization continues to grow, our people remain focused on APUC's vision—to be the utility company most admired by its customers, communities and investors for its people, passion, and performance.

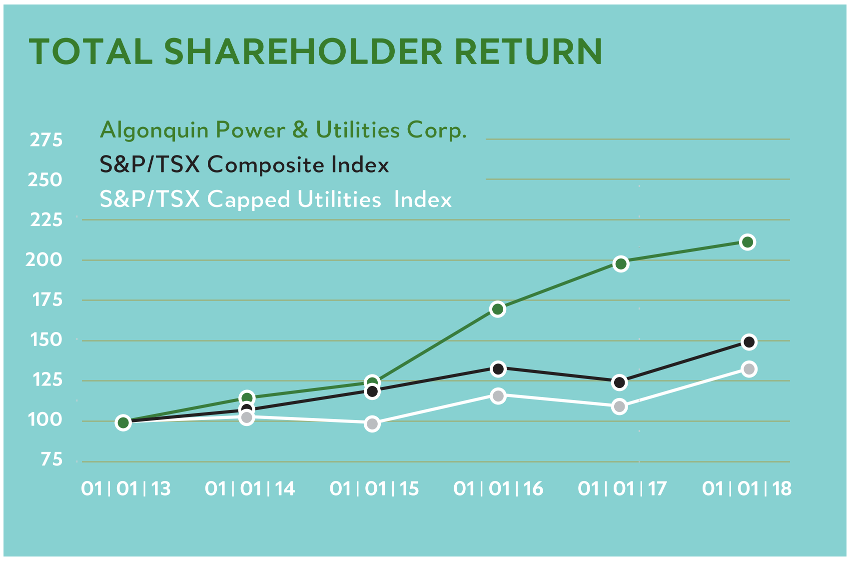
LONG TERM SUSTAINABLE GROWTH DELIVERS SHAREHOLDER VALUE

APUC's value proposition is founded on delivering a compelling total shareholder return ("TSR") to our investors which is comprised of share price appreciation and a safe and growing dividend supported by per share earnings growth.

We are very pleased to have achieved strong performance on both fronts in 2017. Our sustained financial performance powered by our acquisition of Empire supported the decision by our Board of Directors to approve a 10% increase in our dividend in January, 2017. This marked our seventh consecutive year of double-digit annual dividend growth, a cadence of which we are proud.

Dividend growth in 2017 was supported by year-over-year adjusted earnings per share growth of 30% and adjusted funds from operations growth of 72%. Consistent execution against our corporate objectives has supported a level of share performance that is among the highest of our peers. Our 2017 TSR of 26.3% was materially above the comparable Canadian benchmarks, and our





average annual return over the past five years of 19.6% is a positive reflection of the efforts we have made to profitably expand our business.

A TRANSFORMATIONAL YEAR OF GROWTH FOR LIBERTY UTILITIES

On January 1, 2017, a transformative milestone was reached by our Liberty Utilities Business Group with the completion of the Empire acquisition. The growth in the scale of our regulated utility business through this acquisition was profound. We welcomed over 800 new members to our Liberty Utilities team and assumed responsibility to provide safe, reliable, and affordable electric, natural gas and water service to more than 200,000 new customers. Through the dedicated efforts of our combined workforce, the integration of the businesses has been seamless to our customers, regulators, and investors.

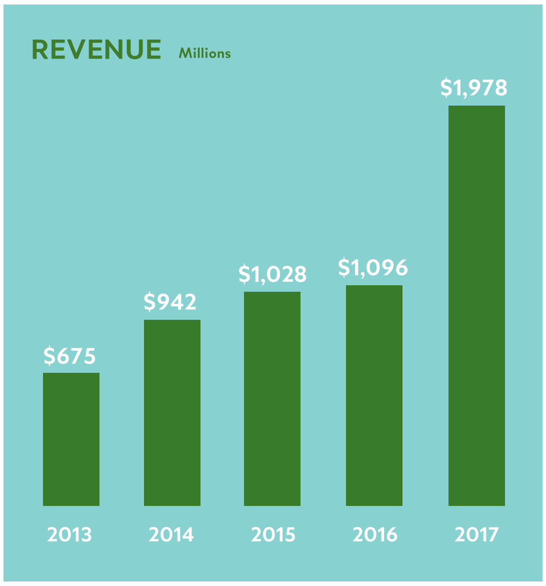
During 2017, we unveiled one of the driving factors behind the acquisition of Empire. Persistent improvement in the cost-competitiveness of renewable generation has supported our "Greening the Fleet" initiative to bring up to 800 MW of new wind generation to replace coal fired generation in the Midwest through our Customers Savings Plans program. This builds on our success in California where we commissioned 50 MW of solar generation dedicated to serving the needs of our California electric customers.

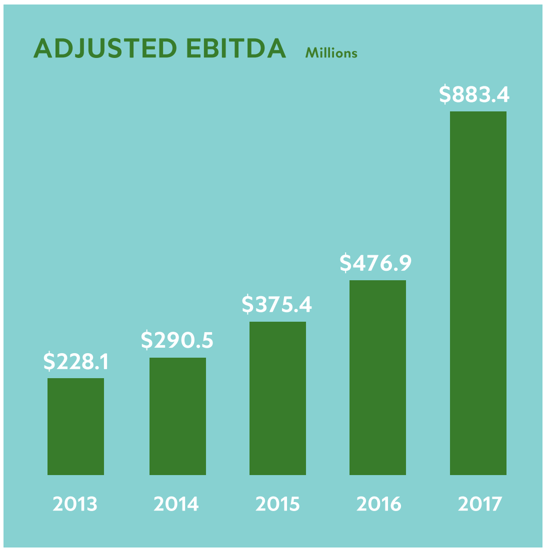
STRONG PERFORMANCE WITHIN LIBERTY POWER

We re-branded our non-regulated renewable generation group in 2017 under the "Liberty Power" banner, symbolizing the converging role that the development of renewable energy resources is playing in the delivery of regulated electric utility services. The year was marked by further expansion and diversification of our Liberty Power generating portfolio with the commissioning of our 150 MW Deerfield wind project in Michigan and an additional 10 MW solar project in California. Material progress was also made on our development opportunities, with construction in full swing on both our 75 MW Amherst Island wind project in Ontario and our 75 MW Great Bay solar project in Maryland. Development efforts also continue for additional commercially secured projects representing approximately $400 million of investment potential.

EXPANDING OUR INVESTMENT HORIZONS BEYOND NORTH AMERICA

In late 2017, APUC expanded its business into the international energy and water infrastructure arena. On November 1, 2017, APUC announced that it had formed AAGES, a new joint venture development entity focused on the development of energy and water infrastructure projects on a global scale. Through AAGES, APUC has gained access to a curated collection of international project initiatives. Our partner in the joint venture, Seville, Spain-based Abengoa, S.A., has a 70-year track





record of providing engineering and construction activities to a global client base.

Concurrent with the formation of AAGES, we announced a US$608 million equity investment in Atlantica, an owner and proven operator of a diverse, contracted portfolio of 22 infrastructure facilities representing 1.7 GW of clean power generating capacity, 1,770 km of electric transmission lines, and two desalination plants in selected global markets. Atlantica's portfolio is complementary to APUC's existing operations, and APUC's commitment to AAGES is expected to strengthen Atlantica's prospects through the addition of new assets, thereby accelerating the growth of its cash available for distribution.

OUR COMMITMENT TO RESPONSIBLE, SUSTAINABLE GROWTH AND OPERATIONS

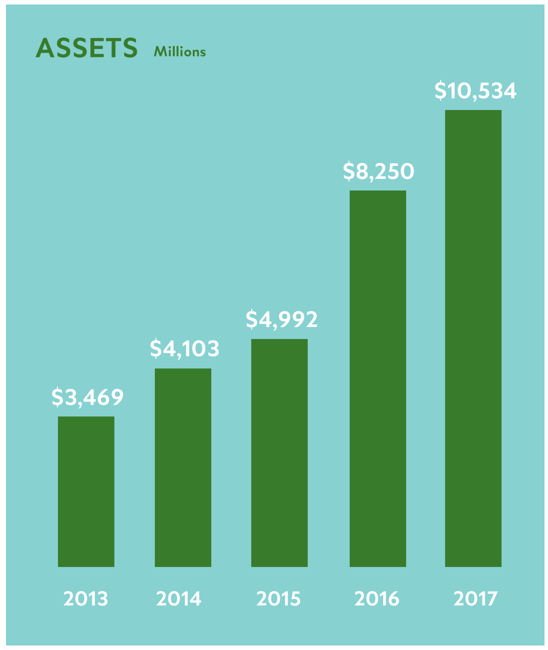
Over the course of 2017, we saw the continued evolution of our corporate governance practices with the goal of remaining at the forefront of the perpetual change taking place in this area. During the year, we established a Risk Committee within our Board of Directors that brings additional oversight and prominence to our Enterprise Risk Management function. We also strengthened our commitment to diversity, both through the adoption of a company-wide Diversity Policy as well as our membership the in "30% Club" which recognizes the important benefits that a gender diverse board and management team can bring to APUC.

We continued to pursue and promote responsible and sustainable business practices throughout our operations during 2017, including proudly marking our 10th consecutive year of reporting under the Carbon Disclosure Project.

INDUSTRY CHANGES BRING FUTURE OPPORTUNITIES

It is becoming increasingly evident that transformative changes are under way in the provision of utility services. Technological advancements coupled with evolving customer desires for greater influence and control are driving continuing change in an industry once dominated by slow moving monopolies. Technologies such as low cost renewable solar generation and flexible energy storage are ready to play an essential part in the utility of the future. We continue to apply our entrepreneurial spirit to generate new opportunities from these changes and are confident in our role in creating a sustainable energy and water future.

Our strategy for 2018 is focused on setting the stage for international investment, advancing our "Greening the Fleet" plan in the Midwest region, and seeking new project opportunities for our renewables business. An essential component of our long-term strategic plan is to make the investments necessary to fortify our systems, improve the resilience of our company as a whole, and equip our businesses to capitalize on the rapid changes taking place in our core markets. These initiatives will enable material investment



It is our belief that the slow-moving, conservative utility of the past must now embrace an agile and entrepreneurial mindset and culture to thrive in the utility business for the long term.

opportunities and a cost-effective means to meet the changing needs of our customers.

BUILDING OUR FUTURE WITH OUR PEOPLE

Through the dedication of our highly capable team of employees, APUC delivered strong performance and reached a number of important milestones in 2017. We are grateful for the productive relationships our employees continue to cultivate with our customers, landowners, suppliers, local communities, and regulators. This past year, we welcomed new members to our family of companies and we look forward to growing together with them as we expand our businesses outside our current borders. Our gratitude also goes to our Board of Directors, whose oversight and guidance has been invaluable as we build a resilient and thriving business. Finally, we would like to express our sincere appreciation to our shareholders for the support they continue to provide us.

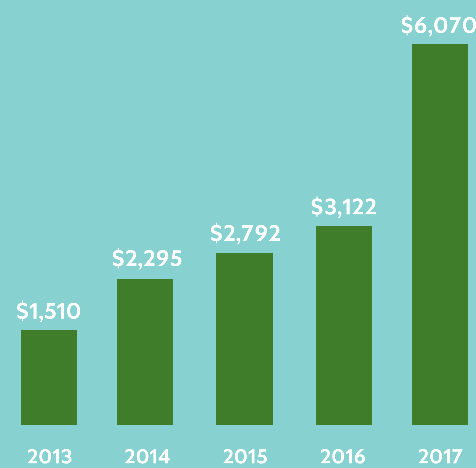
We look forward to the future confidently, ready to embrace new opportunities.

Ian Robertson
CEO

Ken Moore
Chairman of the
Board of Directors

Our "Why" - We believe the world needs a sustainable energy and water future, and together, we are creating something special that will make a real difference to all of our stakeholders.

MARKET CAPITALIZATION Millions
as of December 31, 2017



Algonquin Power & Utilities Corp.

Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company" or the "Corporation") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2017. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's consolidated financial statements for the years ended December 31, 2017 and 2016. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

Unless otherwise indicated, financial information provided for the years ended December 31, 2017 and 2016 has been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

This MD&A is based on information available to management as of March 7, 2018.

Caution Concerning Forward-looking Statements, Forward-looking Information and non-GAAP Measures

Forward-looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC's target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the "safe harbor" provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation's acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "*Enterprise Risk Management*" and in the Corporation's AIF.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, one-time costs of arranging tax equity financing, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations, unrealized mark-to-market revaluation impacts, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. For 2017, the one-time impact of the revaluation of U.S. non-regulated net deferred income tax assets as a result of the U.S. federal corporate income tax rate reduction from 35% to 21% enacted in December 2017 is adjusted as it is also considered a non-recurring item not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, which can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's most recent AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flows to support a growing dividend and share price appreciation.

APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 per common share per annum. Based on exchange rates as at February 28, 2018, the quarterly dividend is equivalent to Cdn $0.1492 per common share or Cdn $0.5969 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Power Group, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets; and the Liberty Utilities Group. which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 87% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which as of December 31, 2017 had a production-weighted average remaining contract life of approximately 15 years.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 762,000 customers. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers and seeks to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisition of additional utility systems.

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas. The electric utility systems in total serve approximately 265,000 electric connections and operate a fleet of generation assets with a net capacity of 1,424 MW.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri serving approximately 337,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, and Texas which together serve approximately 160,000 connections.

Corporate Development

The Company is presently developing a portfolio of renewable power generation projects that, when constructed, will add approximately 361 MW of generation capacity from wind and solar powered generating facilities and, that when completed and on-line, will have a production-weighted average contract life of approximately 22 years.

2017 Major Highlights

Corporate Highlights

Strong Year of Operating Results

APUC recorded a strong twelve months of operating results relative to the same period last year.

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31		
	2017	2016	Change
Net earnings attributable to shareholders	**$193.1**	$130.9	**48%**
Adjusted Net Earnings	**$292.1**	$161.6	**81%**
Adjusted EBITDA	**$883.4**	$476.9	**85%**
Net earnings per common share	**$0.48**	$0.44	**9%**
Adjusted Net Earnings per common share	**$0.74**	$0.57	**30%**

Declaration of Canadian Equivalent 2018 First Quarter Dividend of Cdn $0.1492 (U.S. $0.1165) per Common Share

On March 1, 2018, APUC announced that the Board of Directors of APUC declared a first quarter 2018 dividend of U.S. $0.1165 per common share payable on April 13, 2018 to shareholders of record on March 29, 2018. Based on the Bank of Canada exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2018 dividend is set at Cdn $0.1492 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Total
U.S. dollar dividend	$0.1165	$0.1165	$0.1165	$0.1165	$0.4660
Canadian dollar equivalent	$0.1593	$0.1480	$0.1478	$0.1492	$0.6043

Investment in Joint Venture with Abengoa and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC entered into an agreement to create a joint venture, Abengoa-Algonquin Global Energy Solutions ("AAGES"), with Seville, Spain-based Abengoa, S.A (MCE: ABG) ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608 million, based on a price of U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per share payable two years after closing, subject to certain conditions. The transaction is expected to close sometime in the first quarter of 2018.

Completion of The Empire District Electric Company Acquisition and Financing

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of The Empire District Electric Company ("Empire") for an aggregate purchase price of approximately U.S. $2.414 billion including the assumption of approximately U.S. $0.9 billion of debt ("Empire Acquisition").

Empire is a Joplin, Missouri-based vertically integrated, regulated electric, gas and water utility with approximately 1.4 GW of generating capacity serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Empire Acquisition, the final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Empire Acquisition ("Acquisition Facility"). As at March 6, 2018, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

U.S. $750 Million Private Placement Offering

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750 million of senior unsecured notes on a private placement basis to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and an effective interest rate of 3.6% (inclusive of interest rate hedges).

Corporate Financings Completed:

$576 Million Bought Deal Offering of Common Shares

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result, a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

U.S. Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. Tax Reform") was signed into law in the U.S., which, amongst other significant changes, reduced the U.S. federal corporate tax rate from 35% to 21%.

As a result of U.S. Tax Reform, the Company is required to revalue its U.S. deferred income tax assets and liabilities based on the new tax rate. This revaluation resulted in a one time non-cash accounting charge of $22.4 million to be recorded in the Company's consolidated statement of operations for the quarter and year ended December 31, 2017.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company expects its effective tax rate in 2018 on its consolidated worldwide net income to be below 20%.

Additional detail on U.S. Tax Reform can be found later in this document under Corporate and Other expenses.

Change to U.S. Dollar Reporting

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Over 90% of APUC's consolidated revenue, EBITDA and assets are derived from operations in the United States. In addition, APUC's dividend is denominated in U.S. dollars and the Company's common shares are listed on the New York Stock Exchange. The Company believes that the change in reporting to U.S. dollars will provide improved information to investors and allow for better assessment of its results without the effects of the change in currency on 90% of its operations.

Liberty Power Group Highlights

Completion of the Deerfield Wind Project

On February 21, 2017, the Deerfield Wind Facility achieved commercial operations ("COD"). The project consists of a 150 MW wind generating facility located in central Michigan. On May 10, 2017, tax equity financing of approximately U.S. $166.6 million was completed. The Deerfield Wind Facility is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is expected to generate 555.2 GW-hrs annually. The project has a 20 year Power Purchase Agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

On January 11, 2017, the Liberty Power Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds were used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Liberty Utilities Group Highlights

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million. The Liberty Utilities Group has pending rate case filings in progress that are expected to be completed in 2018 that if successful will represent an increase in rates in the amount of U.S. $44.9 million.

Application to Develop up to 800 MW of Wind in the Midwest

On October 31, 2017, Empire announced a proposed plan to phase out its Asbury coal generation facility and expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. The plan projects cost savings for customers of U.S. $172.0 - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. Orders from the various jurisdictions are anticipated by June 2018.

Granite Bridge Project

On December 4, 2017, the Liberty Utilities Group announced plans for the development of a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project is estimated to cost between U.S. $320.0 million and U.S. $360 million and would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York State. The total purchase price for the transaction is U.S. $70.0 million, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

Acquisition of the Perris Water Distribution System

On August 10, 2017, the Company's board approved the acquisition of two water distribution systems serving approximately 4,000 customers in the City of Perris, California. The anticipated purchase price of U.S. $11.5 million is expected to be established as rate base during the regulatory approval process. Liberty Utilities was the successful bidder in the city's request for proposal process and in July 2017 the Perris City council voted to approve the sale to Liberty Utilities. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission ("CPUC") in Q1 2018, with approval expected in late 2018.

Completion of the Luning Solar Facility

On February 15, 2017, the Liberty Utilities Group acquired control of a 50 MWac solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The facility is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the facility is included in the rate base of the Calpeco Electric System as energy produced from the project is being consumed by the utility's customers.

2017 Fourth Quarter Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Three Months Ended December 31 2017	2016
Revenue	**$ 523.4**	$ 310.2
Net earnings attributable to shareholders	**60.0**	46.3
Cash provided by operating activities	**169.8**	121.9
Adjusted Net Earnings[1]	**85.9**	51.4
Adjusted EBITDA[1]	**233.4**	138.3
Adjusted Funds from Operations[1]	**159.1**	96.4
Dividends declared to common shareholders	**64.0**	39.2
Weighted average number of common shares outstanding	**412,632,308**	273,952,963
Per share		
Basic net earnings	**$ 0.14**	$ 0.16
Diluted net earnings	**$ 0.14**	$ 0.16
Adjusted Net Earnings[1,2]	**$ 0.20**	$ 0.18
Dividends declared to common shareholders	**$ 0.15**	$ 0.14

[1] See Non-GAAP Financial Measures

[2] APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2715 as compared to 1.3343 in the same period in 2016. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2017, APUC reported total revenue of $523.4 million as compared to $310.2 million during the same period in 2016, an increase of $213.2 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	$	**310.2**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.4)
Wind Canada: Increase primarily due to higher production and annual rate increases in PPAs.		1.9
Wind U.S.: Increase primarily due to higher overall production.		1.3
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		2.9
Other:		(0.5)
		5.4
New Facilities		
Wind US: Acquisition of Deerfield Wind Facility in March 2017.		9.5
Solar US: Bakersfield II Solar Facility was placed in service in December 2016.		0.3
		9.8
Foreign Exchange		**(2.3)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(7.2)
Gas: Increase primarily due to higher demand and pass through gas costs at the New England and Midstates Gas Systems from increased heating degree days, partially offset by lower pass through gas costs at the EnergyNorth Gas System.		14.5
Water: Decrease primarily due to divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(2.9)
Other: Decrease primarily due to lower contracted services.		(1.8)
		2.6
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($180.8 million) on January 1, 2017 and the Luning Solar Facility ($3.6 million) on February 15, 2017.		184.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		14.6
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.6
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.0
		201.6
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(11.0)**
Current Period Revenue	$	**523.4**

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2017, net earnings attributable to shareholders totaled $60.0 million as compared to $46.3 million during the same period in 2016, an increase of $13.7 million or 29.6%. The increase was due to a $101.6 million increase in earnings from operating facilities and a $1.1 million decrease in acquisition related costs. These items were partially offset by a $5.6 million increase in administration charges, $35.4 million increase in depreciation and amortization expenses, $0.3 million decrease in foreign exchange gain, $3.7 million increase in interest expense, $0.6 million decrease in interest, dividend, equity and other income, $3.3 million decrease in other gains, $2.3 million decrease in gains on long lived assets, $8.9 million decrease in gains from derivative instruments, $2.4 million decrease in net effect of non-controlling interests, and a $26.5 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2016.

During the three months ended December 31, 2017, cash provided by operating activities totaled $169.8 million as compared to cash provided by operating activities of $121.9 million during the same period in 2016. During the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million compared to Adjusted Funds from Operations of $96.4 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended December 31, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended December 31, 2017, Adjusted EBITDA totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31		
	2017	**2016**	**2015**
Revenue	**$ 1,977.8**	$ 1,096.0	$ 1,027.9
Net earnings attributable to shareholders from continuing operations	**193.1**	130.9	118.5
Net earnings attributable to shareholders	**193.1**	130.9	117.5
Cash provided by operating activities	**457.8**	287.9	261.9
Adjusted Net Earnings[1]	**292.1**	161.6	121.5
Adjusted EBITDA[1]	**883.4**	476.9	375.4
Adjusted Funds from Operations[1]	**614.5**	356.4	287.4
Dividends declared to common shareholders	**242.5**	149.2	124.8
Weighted average number of common shares outstanding	**382,323,434**	271,832,430	253,172,088
Per share			
Basic net earnings from continuing operations	**$ 0.48**	$ 0.44	$ 0.43
Basic net earnings	**$ 0.48**	$ 0.44	$ 0.42
Diluted net earnings	**$ 0.47**	$ 0.44	$ 0.42
Adjusted Net Earnings[1,2]	**$ 0.74**	$ 0.57	$ 0.46
Dividends declared to common shareholders	**$ 0.61**	$ 0.55	$ 0.49
Total assets	**10,533.6**	8,249.5	4,991.7
Long term debt[3]	**3,864.5**	4,272.0	1,486.8

1 See Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

3 Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the twelve months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2980 as compared to 1.3253 in the same period in 2016. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2017, APUC reported total revenue of $1,977.8 million as compared to $1,096.0 million during the same period in 2016, an increase of $881.8 million or 80.5%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Comparative Prior Period Revenue	$	**1,096.0**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and lower pricing in Hydro Quebec PPA renewals, coupled with lower production in the Maritime and Western Regions.		(7.5)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		2.2
Wind U.S.: Decrease primarily due to lower REC pricing, partially offset by higher production at Minonk and Shady Oaks Wind Facilities.		(0.8)
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.6)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		4.2
Other: Decrease primarily due to the shutdown of the hydro mulch business at the Sanger Thermal Facility.		(1.9)
		(4.8)
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		40.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.		2.1
		42.9
Foreign Exchange		**(3.6)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to lower pass through energy costs at the Calpeco Electric System.		(8.3)
Gas: Increase primarily due to higher consumption at the EnergyNorth and New England Gas Systems due to higher heating degree days combined with higher pass through gas costs at the Peach State Gas System.		38.0
Water: Decrease primarily due divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(6.5)
Other: Decrease primarily due to lower contracted services.		(6.0)
		17.2
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($754.6 million) on January 1, 2017 and the Luning Solar Facility ($14.7 million) on February 15, 2017.		769.3
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		46.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		2.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		8.1
		827.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(20.7)**
Current Period Revenue	$	**1,977.8**

A more detailed discussion of these factors is presented within the business unit analysis.

For the twelve months ended December 31, 2017, net earnings attributable to shareholders totaled $193.1 million as compared to $130.9 million during the same period in 2016, an increase of $62.2 million. The increase was due to a $401.4 million increase in earnings from operating facilities, $1.4 million increase in interest, dividend, equity and other income, and $23.6 million increase in net effect of non-controlling interests. These items were partially offset by an $18.2 million increase in administration charges, $139.5 million increase in depreciation and amortization expenses, $0.8 million decrease in foreign exchange gains, $71.0 million increase in interest expense, $11.8 million decrease in other gains, $50.8 million increase in acquisition costs, $0.8 million decrease in gain on long lived assets, $13.2 million decrease on gains from derivative instruments and $58.1 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*) as compared to the same period in 2016.

During the twelve months ended December 31, 2017, cash provided by operating activities totaled $457.8 million as compared to cash provided by operating activities of $287.9 million during the same period in 2016. During the twelve months ended December 31, 2017, Adjusted Funds from Operations, a non-GAAP measure, totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million the same period in 2016, an increase of $258.1 million.

Adjusted EBITDA in the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2017 totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. Adjusted EBITDA for the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Liberty Power Operating Profit	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3
Liberty Utilities Group Operating Profit	**180.7**	85.9	**694.1**	300.5
Administrative Expenses	**(18.7)**	(13.1)	**(64.5)**	(46.3)
Other Income & Expenses	**0.6**	3.6	**2.9**	5.4
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9
Change in Adjusted EBITDA ($)	**$ 95.1**		**$ 406.5**	
Change in Adjusted EBITDA (%)	**68.8%**		**85.2%**	

Change in Adjusted EBITDA	Three Months Ended December 31, 2017			
(all dollar amounts in $ millions)	Power	Utilities	Corporate	Total
Prior period balances	**$ 61.9**	**$ 85.9**	**$ (9.5)**	**$ 138.3**
Existing Facilities	7.8	(5.6)	(3.0)	(0.8)
New Facilities	3.0	97.3	—	100.3
Rate Cases	—	7.1	—	7.1
Foreign Exchange Impact	(1.9)	(4.0)	—	(5.9)
Administrative Expenses	—	—	(5.6)	(5.6)
Total change during the period	**$ 8.9**	**$ 94.8**	**$ (8.6)**	**$ 95.1**
Current period balances	**$ 70.8**	**$ 180.7**	**$ (18.1)**	**$ 233.4**

Change in Adjusted EBITDA	Twelve Months Ended December 31, 2017			
(all dollar amounts in $ millions)	Power	Utilities	Corporate	Total
Prior period balances	**$ 217.3**	**$ 300.5**	**$ (40.9)**	**$ 476.9**
Existing Facilities	0.9	(4.5)	(2.6)	(6.2)
New Facilities	34.9	381.0	—	415.9
Rate Cases	—	23.8	—	23.8
Foreign Exchange Impact	(2.2)	(6.7)	—	(8.9)
Administration Expenses	—	—	(18.1)	(18.1)
Total change during the period	**$ 33.6**	**$ 393.6**	**$ (20.7)**	**$ 406.5**
Current period balances	**$ 250.9**	**$ 694.1**	**$ (61.6)**	**$ 883.4**

LIBERTY POWER GROUP

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Long Term Average Resource	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Hydro Facilities:						
Maritime Region	**37.6**	**34.9**	21.9	**148.2**	**129.7**	144.1
Quebec Region	**72.6**	**67.5**	64.0	**273.3**	**270.6**	267.5
Ontario Region	**31.9**	**30.6**	28.6	**136.0**	**129.5**	126.8
Western Region	**12.6**	**10.5**	18.1	**65.0**	**59.6**	66.1
	154.7	**143.5**	132.6	**622.5**	**589.4**	604.5
Wind Facilities:						
St. Damase	**22.7**	**24.0**	20.4	**76.9**	**74.3**	74.4
St. Leon	**121.4**	**138.7**	130.8	**430.2**	**444.2**	417.3
Red Lily[1]	**24.1**	**29.2**	25.4	**88.5**	**91.6**	82.6
Morse	**30.5**	**33.1**	27.7	**108.8**	**106.4**	94.8
Sandy Ridge	**43.6**	**42.0**	51.8	**158.3**	**153.3**	155.8
Minonk	**189.8**	**203.5**	184.9	**673.7**	**673.7**	635.8
Senate	**140.0**	**126.6**	136.7	**520.4**	**492.8**	504.4
Shady Oaks	**100.5**	**108.7**	104.4	**355.6**	**365.5**	323.9
Odell[2]	**238.0**	**244.6**	211.2	**831.8**	**807.2**	297.7
Deerfield[3]	**160.0**	**164.3**	—	**472.6**	**449.3**	—
	1,070.6	**1,114.7**	893.3	**3,716.8**	**3,658.3**	2,586.7
Solar Facilities:						
Cornwall	**2.2**	**2.1**	1.9	**14.7**	**14.4**	15.6
Bakersfield I	**8.9**	**8.7**	7.4	**52.8**	**48.3**	45.9
Bakersfield II[4]	**4.1**	**4.0**	—	**24.4**	**22.2**	—
	15.2	**14.8**	**9.3**	**91.9**	**84.9**	**61.5**
Renewable Energy Performance	**1,240.5**	**1,273.0**	1,035.2	**4,431.2**	**4,332.6**	3,252.7
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**31.8**	30.9	**N/A[5]**	**122.0**	131.0
Sanger	**N/A[5]**	**33.5**	28.8	**N/A[5]**	**86.0**	118.7
		65.3	59.7		**208.0**	249.7
Total Performance		**1,338.3**	1,094.9		**4,540.6**	3,502.4

1 APUC owns a 75% equity interest in the Red Lily Wind Facility but accounts for the facility using the equity method. The production figures represent full energy produced by the facility.

2 The Odell Wind Facility achieved COD on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility.

3 The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The long-term average resources ("LTAR") and production noted above represents all production from the date of COD.

4 The Bakersfield II Solar Facility achieved COD on January 11, 2017 in accordance with the terms of the PPA. The LTAR and production noted above represents all production from the date of COD.

5 Natural gas fired co-generation facility.

2017 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2017, the Liberty Power Group generated 1,338.3 GW-hrs of electricity as compared to 1,094.9 GW-hrs during the same period of 2016.

For the three months ended December 31, 2017, the hydro facilities generated 143.5 GW-hrs of electricity as compared to 132.6 GW-hrs produced in the same period in 2016, an increase of 8.2%. Electricity generated represented 92.8% of long-term average resources ("LTAR") as compared to 85.7% during the same period in 2016. During the quarter, all regions were below their respective LTAR.

For the three months ended December 31, 2017, the wind facilities produced 1,114.7 GW-hrs of electricity as compared to 893.3 GW-hrs produced in the same period in 2016, an increase of 24.8%. The higher generation was primarily due to the addition of the Deerfield Wind Facility which achieved COD on February 21, 2017. This increase was partially offset by lower production at the Senate and Sandy Ridge Wind Facilities. During the three months ended December 31, 2017, the wind facilities (excluding the Deerfield Wind Facility) generated electricity equal to 104.3% of LTAR as compared to 98.0% during the same period in 2016.

For the three months ended December 31, 2017, the solar facilities generated 14.8 GW-hrs of electricity as compared to 9.3 GW-hrs of electricity in the same period in 2016, an increase of 59.1%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 2.7% below its LTAR as compared to 16.2% below in the same period in 2016.

For the three months ended December 31, 2017, the thermal facilities generated 65.3 GW-hrs of electricity as compared to 59.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 136.9 billion lbs of steam as compared to 129.3 billion lbs of steam during the same period in 2016.

2017 Annual Liberty Power Group Performance

For the twelve months ended December 31, 2017, the Liberty Power Group generated 4,540.6 GW-hrs of electricity as compared to 3,502.4 GW-hrs during the same period of 2016.

For the twelve months ended December 31, 2017, the hydro facilities generated 589.4 GW-hrs of electricity as compared to 604.5 GW-hrs produced in the same period in 2016, a decrease of 2.5%. Electricity generated represented 94.7% of long-term projected average resources as compared to 97.1% during the same period in 2016. The decrease is primarily due to reduced hydrology in the Maritime and Western Region's partially offset by increased generation in the Quebec and Ontario Regions.

For the twelve months ended December 31, 2017, the wind facilities produced 3,658.3 GW-hrs of electricity as compared to 2,586.7 GW-hrs produced in the same period in 2016, an increase of 41.4%. During the twelve months ended December 31, 2017, the wind facilities generated electricity equal to 98.4% of LTAR as compared to 93.9% during the same period in 2016. The increase in production was primarily due to higher production at the Shady Oaks, Minonk and St. Leon Wind Facilities as well as the incremental electricity generated at the Deerfield and Odell Wind Facilities which achieved COD on February 21, 2017 and July 29, 2016, respectively.

For the twelve months ended December 31, 2017, the solar facilities generated 84.9 GW-hrs of electricity as compared to 61.5 GW-hrs of electricity produced in the same period in 2016, an increase of 38.0%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 7.1% below its LTAR as compared to 8.9% below in the same period in 2016.

For the twelve months ended December 31, 2017, the thermal facilities generated 208.0 GW-hrs of electricity as compared to 249.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 559.1 billion lbs of steam as compared to 552.5 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31				Twelve Months Ended December 31			
		2017		**2016**		**2017**		**2016**
Revenue[1]								
Hydro	**$**	**14.0**	$	14.6	**$**	**58.2**	$	66.5
Wind		**54.0**		42.6		**171.6**		128.2
Solar		**2.0**		1.6		**14.0**		12.9
Thermal		**11.1**		8.2		**38.8**		35.5
Total Revenue	**$**	**81.1**	$	67.0	**$**	**282.6**	$	243.1
Less:								
Cost of Sales - Energy[2]		**(1.9)**		(1.8)		**(6.5)**		(5.8)
Cost of Sales - Thermal		**(5.8)**		(4.4)		**(18.9)**		(15.5)
Realized gain/(loss) on hedges[3]		**—**		—		**(0.7)**		(1.0)
Net Energy Sales	**$**	**73.4**	$	60.8	**$**	**256.5**	$	220.8
Renewable Energy Credits ("REC")[4]		**5.5**		6.3		**17.1**		20.2
Other Revenue		**0.1**		0.5		**0.5**		2.4
Total Net Revenue	**$**	**79.0**	$	67.6	**$**	**274.1**	$	243.4
Expenses & Other Income								
Operating expenses		**(21.9)**		(20.2)		**(86.7)**		(72.3)
Interest, dividend, equity and other income		**1.1**		0.9		**3.7**		5.2
HLBV income[5]		**12.6**		13.6		**59.8**		41.0
Divisional Operating Profit[6,7]	**$**	**70.8**	$	61.9	**$**	**250.9**	$	217.3

1 While most of the Liberty Power Group's PPAs include annual rate increases, a change to the weighted average production levels resulting from higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division as compared to the same period in the prior year.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Hydro Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements *note 25(b)(iv)*.

4 Qualifying renewable energy projects receive RECs for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source.

5 HLBV income represents the value of net tax attributes earned by the Liberty Power Group in the period primarily from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

6 Certain prior year items have been reclassified to conform to current year presentation.

7 See *Non-GAAP Financial Measures*.

2017 Fourth Quarter Operating Results

For the three months ended December 31, 2017, the Liberty Power Group's facilities generated $70.8 million of operating profit as compared to $61.9 million during the same period in 2016, which represents an increase of $8.9 million or 14.4%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31
Prior Period Operating Profit	**$ 61.9**
Existing Facilities	
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.	(0.6)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.	1.9
Wind U.S.: Increase primarily due to higher production and HLBV income at the Minonk and Odell Wind Facilities.	4.7
Solar Canada: Increase primarily due to higher production.	0.1
Solar U.S.: Increase primarily due to higher production.	0.3
Thermal: Increase primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.	1.3
Other:	0.1
	7.8
New Facilities	
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.	2.2
Solar U.S.: Bakersfield II was placed in service in December 2016.	0.8
	3.0
Foreign Exchange	**(1.9)**
Current Period Divisional Operating Profit	**$ 70.8**

2017 Annual Operating Results

For the twelve months ended December 31, 2017, the Liberty Power Group's facilities generated $250.9 million of operating profit as compared to $217.3 million during the same period in 2016, which represents an increase of $33.6 million or 15.5%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	**$**	**217.3**
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and pricing settlement in the Quebec Region, coupled with lower production in the Maritime and Western Regions.		(8.2)
Wind Canada: Increase primarily due to higher production and annual rate increases.		1.8
Wind U.S.: Increase primarily due to higher HLBV income and higher production at the Minonk and Shady Oaks Wind Facilities.		6.7
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.2)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at to the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		0.4
Other:		0.8
		0.9
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		31.3
Solar U.S.: Bakersfield II was placed in service in December 2016.		3.6
		34.9
Foreign Exchange		**(2.2)**
Current Period Divisional Operating Profit	**$**	**250.9**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, the Liberty Utilities Group completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

Utility System Type

(all dollar amounts in U.S. $ millions)	As at December 31 2017 Assets	2017 Total Connections[1]	2016 Assets	2016 Total Connections[1]
Electricity	**$ 2,479.9**	**265,000**	$ 378.4	94,000
Natural Gas	**996.1**	**337,000**	845.9	293,000
Water and Wastewater	**462.6**	**160,000**	516.4	178,000
Total	**$ 3,938.6**	**762,000**	$ 1,740.7	565,000
Accumulated Deferred Income Taxes Liability	**$ 392.8**		$ 194.7	

[1] Total Connections represents the sum of all active and vacant connections.

The Liberty Utilities Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 265,000 connections in the states of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 337,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 160,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

2017 Fourth Quarter Usage Results

Electric Distribution Systems

	Three Months Ended December 31 2017	2016
Average Active Electric Connections For The Period		
Residential	224,400	80,600
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**263,600**	**93,100**
Customer Usage (GW-hrs)		
Residential	571.7	142.5
Commercial and industrial	882.3	225.0
Total Customer Usage (GW-hrs)	**1,454.0**	**367.5**

For the three months ended December 31, 2017, the electric distribution systems' usage totaled 1,454.0 GW-hrs as compared to 367.5 GW-hrs for the same period in 2016, an increase of 1,086.5 GW-hrs or 295.6%. The addition of Empire accounted for 1,091.6 GW-hrs of the increase. Excluding Empire, usage was 5.1 GW-hrs, or 1.4%, lower due to lower commercial usage at the Calpeco Electric System.

Natural Gas Distribution Systems

	Three Months Ended December 31	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	286,700	248,100
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,400**	**274,700**
Customer Usage (MMBTU)		
Residential	5,196,000	3,737,000
Commercial and industrial	4,282,000	3,446,000
Total Customer Usage (MMBTU)	**9,478,000**	**7,183,000**

For the three months ended December 31, 2017, usage at the natural gas distribution systems totaled 9,478,000 MMBTU as compared to 7,183,000 MMBTU during the same period in 2016, an increase of 2,295,000 MMBTU, or 32.0%. The addition of Empire accounted for 1,069,000 MMBTU of the increase. Excluding Empire, usage was 1,226,000 MMBTU, or 17.1%, higher primarily due to increased consumption at the Midstates and Peach State Gas Systems.

Water and Wastewater Distribution Systems

	Three Months Ended December 31	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	41,400	41,100
Water distribution connections	111,800	129,400
Total Average Active Connections For The Period	**153,200**	**170,500**
Gallons Provided		
Wastewater treated (millions of gallons)	555	542
Water provided (millions of gallons)	3,909	4,113
Total Gallons Provided	**4,464**	**4,655**

During the three months ended December 31, 2017, the water and wastewater distribution systems provided approximately 3,909 million gallons of water to its customers and treated approximately 555 million gallons of wastewater as compared to 4,113 million gallons of water provided and 542 million gallons of wastewater treated during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 289 million gallons, or 7%, higher.

2017 Fourth Quarter Operating Results

	Three Months Ended December 31			
	2017 U.S. $ (millions)	**2016 U.S. $ (millions)**	**2017 Can $ (millions)**	**2016 Can $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 187.0**	$ 46.9	**$ 237.8**	$ 62.5
Less: cost of sales – electricity	**(51.6)**	(20.6)	**(65.6)**	(27.5)
Net Utility Sales - electricity	**135.4**	26.3	**172.2**	35.0
Utility natural gas sales and distribution	**109.8**	85.1	**140.0**	114.0
Less: cost of sales – natural gas	**(53.1)**	(39.8)	**(67.7)**	(53.2)
Net Utility Sales - natural gas	**56.7**	45.3	**72.3**	60.8
Utility water distribution & wastewater treatment sales and distribution	**31.5**	31.7	**40.1**	42.3
Less: cost of sales – water	**(2.4)**	(2.2)	**(3.1)**	(3.0)
Net Utility Sales - water distribution & wastewater treatment	**29.1**	29.5	**37.0**	39.3
Gas transportation	**9.6**	8.4	**12.3**	10.7
Other revenue	**5.1**	5.0	**6.5**	6.8
Net Utility Sales	**235.9**	114.5	**300.3**	152.6
Operating expenses	**(96.6)**	(50.5)	**(123.1)**	(68.0)
Other income	**1.4**	0.9	**1.8**	1.3
HLBV	**1.3**	—	**1.7**	—
Divisional Operating Profit[1]	**$ 142.0**	$ 64.9	**$ 180.7**	$ 85.9

1 Certain prior year items have been reclassified to conform with current year presentation.

For the three months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $142.0 million as compared to U.S. $64.9 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $180.7 million as compared to $85.9 million during the same period in 2016, which represents an increase of $94.8 million or 110%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Three Months Ended December 31
Prior Period Operating Profit	**$**	**85.9**
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(6.4)
Gas: Increase primarily due to higher consumption at the Midstates and EnergyNorth Gas Systems.		3.1
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(2.2)
Other: Decrease primarily due to lower contracted services.		(0.1)
		(5.6)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($85.9 million) on January 1, 2017 and the Luning Solar Facility ($4.9 million) on February 15, 2017.		90.8
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		4.3
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.9
		97.3
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(4.0)**
Current Period Divisional Operating Profit	**$**	**180.7**

2017 Annual Usage Results

Electric Distribution Systems

	Twelve Months Ended December 31	
	2017	2016
Average Active Electric Connections For The Period		
Residential	223,700	80,400
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**262,900**	**92,900**
Customer Usage (GW-hrs)		
Residential	2,320.1	567.0
Commercial and industrial	3,523.1	895.2
Total Customer Usage (GW-hrs)	**5,843.2**	**1,462.2**

For the twelve months ended December 31, 2017, the electric distribution systems' usage totaled 5,843.2 GW-hrs as compared to 1,462.2 GW-hrs for the same period in 2016, an increase of 4,381.0 GW-hrs. The addition of Empire accounted for 4,386.3 GW-hrs of the increase. Excluding Empire, usage was 5.3 GW-hrs, or 0.4%, lower due to decreased usage by commercial customers at the Granite State Electric System.

Natural Gas Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	287,100	249,000
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,800**	**275,600**
Customer Usage (MMBTU)		
Residential	17,621,000	15,346,000
Commercial and industrial	12,672,000	11,361,000
Total Customer Usage (MMBTU)	**30,293,000**	**26,707,000**

For the twelve months ended December 31, 2017, usage at the natural gas distribution systems totaled 30,293,000 MMBTU as compared to 26,707,000 MMBTU during the same period in 2016, an increase of 3,586,000 MMBTU or 13.4%. The addition of Empire accounted for 2,997,000 MMBTU of the increase. Excluding Empire, usage was 589,000 MMBTU, or 2.2%, higher due to increased usage at the EnergyNorth and New England Gas Systems.

Water and Wastewater Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	41,000	41,100
Water distribution connections	121,400	131,400
Total Average Active Connections For The Period	**162,400**	172,500
Gallons Provided		
Wastewater treated (millions of gallons)	2,226	2,231
Water provided (millions of gallons)	16,905	17,936
Total Gallons Provided	**19,131**	20,167

During the twelve months ended December 31, 2017, the water and wastewater distribution systems provided approximately 16,905 million gallons of water to its customers and treated approximately 2,226 million gallons of wastewater as compared to 17,936 million gallons of water and 2,231 million gallons of wastewater during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 2,295 million gallons, or 14%, higher.

2017 Annual Operating Results

	Twelve Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 763.5**	$ 171.7	**$ 989.2**	$ 228.1
Less: cost of sales – electricity	**(222.4)**	(90.0)	**(288.2)**	(119.8)
Net Utility Sales - electricity	**541.1**	81.7	**701.0**	108.3
Utility natural gas sales and distribution	**346.0**	276.8	**450.7**	371.4
Less: cost of sales – natural gas	**(141.7)**	(105.0)	**(184.5)**	(142.1)
Net Utility Sales - natural gas	**204.3**	171.8	**266.2**	229.3
Utility water distribution & wastewater treatment sales and distribution	**140.1**	137.4	**181.9**	181.7
Less: cost of sales – water	**(9.5)**	(9.2)	**(12.3)**	(12.2)
Net Utility Sales - water distribution & wastewater treatment	**130.6**	128.2	**169.6**	169.5
Gas transportation	**31.2**	25.7	**40.7**	34.3
Other revenue	**11.8**	11.0	**15.2**	14.6
Net Utility Sales	**919.0**	418.4	**1,192.7**	556.0
Operating expenses	**(393.7)**	(196.1)	**(512.0)**	(260.6)
Other income	**4.2**	3.9	**5.4**	5.1
HLBV	**6.2**	—	**8.0**	—
Divisional Operating Profit[1]	**$ 535.7**	$ 226.2	**$ 694.1**	$ 300.5

1 Certain prior year items have been reclassified to conform with current year presentation.

For the twelve months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $535.7 million as compared to U.S. $226.2 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $694.1 million as compared to $300.5 million during the same period in 2016, which represents an increase of $393.6 million or 131%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	$	**300.5**
Existing Facilities		
Gas: Increase primarily due to higher consumption at the EnergyNorth Gas System.		4.5
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(5.3)
Other: Decrease primarily due to lower contracted services.		(3.7)
		(4.5)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($341.4 million) on January 1, 2017 and the Luning Solar Facility ($20.7 million) on February 15, 2017.		362.1
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		11.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		1.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		5.7
		381.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(6.7)**
Current Period Divisional Operating Profit	$	**694.1**

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities Group:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$7.7	Final Order issued in April 2017 approving a U.S. $6.2 million rate increase effective May 1, 2017, and two additional rate increases of approximately U.S. $0.2 million and U.S. $0.3 million effective May 1, 2018 and May 1, 2019, respectively.
New England Gas	Massachusetts	Gas System Enhancement Plan ("GSEP")	$3.8	Final Order issued in April 2017 approving a U.S. $2.9 million rate increase effective May 1, 2017.
Illinois Gas System	Illinois	GRC	$3.0	Final Order issued in May 2017 approving a U.S. $2.2 million rate increase effective June 7, 2017.
Oklahoma Electricity System	Oklahoma	GRC	$3.0	In August 2017, in lieu of authorizing the proposed rate increase the Oklahoma Corporation Commission ordered an immediate increase of U.S. $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.
Calpeco Electric	California	Turquoise Solar Project	$3.0	Final Order issued in December 2017 approving the Settlement Agreement between Liberty Calpeco and the Office of Ratepayer Advocates dated June 30, 2017 which authorizes Liberty Calpeco to acquire, own, and operate the 10 MW, U.S. $15.7 million Turquoise Solar Project.
Calpeco Electric	California	Post-Test Year Adjustment Mechanism	$2.2	Final Order issued in November 2017 approving a U.S $2.2 million rate increase effective January 1, 2018, based on the additional costs related to the Luning Solar Project.
Various	Various	Various	$4.8	Other rate cases closed in 2017 & 2018 with a combined approved rate increase of U.S. $2.8 million include: Entrada Del Oro Water (U.S. $0.2 million), Georgia Gas GRAM (U.S. $0.6 million), New England Gas Decoupling (U.S. $0.2 million), Iowa Gas GRC (U.S. $0.9 million), and Kansas Asbury Environmental and Riverton Cost Recovery Rider (U.S. $0.9 million).

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	GRC	$19.7	On April 28, 2017, filed an application seeking an increase of U.S. $13.7 million (updated to U.S. $14.5 million), plus a step increase of U.S. $6.1 million (updated to U.S. $5.2 million) to be implemented in May 2018. Temporary rates of U.S. $7.8 million were requested to be effective as of July 1, 2017, and on June 30, 2017, the New Hampshire Public Utilities Commission ("NH Commission") approved temporary rates of U.S. $6.8 million (87% of the requested amount) effective July 1, 2017 to be in place until the end of the Company's permanent rate case.
Litchfield Park Water & Sewer	Arizona	GRC	$5.1	On February 28, 2017, filed a water/sewer rate application (test year December 31, 2016) seeking a rate increase of U.S. $5.1 million. New rates are expected to be effective in Q4 2018.
Missouri Gas System	Missouri	GRC	$7.5	On September 29, 2017, filed an application seeking a rate increase of U.S. $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. New rates are expected to be effective in Q3 2018.
Apple Valley Ranchos Water & Park Water Systems	California	GRC	$2.1	On January 2, 2018, filed an application requesting an average rate increase of U.S. $0.7 million and U.S. $1.4 million, respectively and is to set rates for the three year period of 2019 to 2021.
New England Natural Gas System	Massachusetts	GSEP	$6.2	On October 31, 2017, filed the 2018 GSEP application requesting recovery of U.S. $6.2 million (effective May 1, 2018) for replacement of approximately 14 miles of eligible infrastructure.
Various	Various	Various	$4.3	Other pending rate case requests include: Woodmark/Tall Timbers Wastewater Systems (U.S. $1.6 million), Park Water System (U.S. $1.5 million), and Missouri Water System (U.S. $1.2 million).

Completed Rate Cases

On December 14, 2016, the Calpeco Electric System filed an application for approval of the 10 MW Turquoise Solar Project at an estimated cost of U.S. $15.7 million. On June 30, 2017, the Calpeco Electric System and the Office of Ratepayer Advocates filed a joint motion with the Commission requesting approval of its settlement agreement. On December 19, 2017, the Commission issued a decision approving the settlement agreement as filed. The Turquoise Solar Project costs will be included in the Calpeco Electric System's 2019 general rate case and is expected to have a rate impact of approximately U.S. $3.0 million (or 3% increase), which will be offset by future Energy Cost Adjustment Clause ("ECAC)" account reductions. The Turquoise Solar Project is expected to be in service by the fourth quarter of 2018.

On April 29, 2016, the Granite State Electric System filed a rate application seeking a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, plus an additional U.S. $2.4 million annual step increase to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase proposed was U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent rate increase was retroactive to the temporary rate effective date. In April 2017, an order was issued by the New Hampshire Public Utilities Commission ("NHPUC") approving a U.S. $3.8 million rate increase to annual distribution revenues along with an annual increase of U.S. $2.5 million for the revenue requirement associated with 2016 capital investment, both effective May 1, 2017 (achieving 82% of the requested increase). The difference between the U.S. $3.8 million permanent increase and the U.S. $2.4 million temporary rate level that was in effect since July 1, 2016 was collected beginning May 1, 2017. The settlement also provides for two additional annual increases of approximately U.S. $0.2 million and $0.3 million effective May 1, 2018 and May 1, 2019, respectively, to recover the revenue requirement associated with certain significant capital investments made during the prior calendar year.

Pending Regulatory Proceedings

On October 31, 2017, Empire District Electric Company announced a proposed plan to expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. Once fully operational, the project is projected to generate cost savings for customers of U.S. $172.0 million - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval ("Application") of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. On February 6, 2018, the staff of the Missouri Public Service Commission as well as other intervenors filed testimony responsive to the Application. The staff's testimony recommends that the Commission should either approve the projects with conditions or rule that it need not provide approval for the projects to proceed, while other intervenors range in their recommendations from suggesting that the Commission not approve the project to recommending outright approvals. Testimony has now also been received in Oklahoma and Arkansas. In Oklahoma both the staff and the Attorney General recommended approval of the projects and in Arkansas additional details were requested on the proposed projects. The Liberty Utilities Group's local regulatory teams continue to work closely with staffs and commissions from the regulatory agencies and anticipate securing approvals for the projects by June 2018.

CORPORATE DEVELOPMENT ACTIVITIES

The Corporate Development Group works to identify, develop and construct new power generating facilities as well as to identify and acquire operating projects that would be complementary and accretive to the Liberty Power Group's existing portfolio and the Company as a whole. The Corporate Development Group is focused on projects within North America and is committed to working proactively with all stakeholders including local communities.

The development and construction of new power generation facilities involves a number of risks and uncertainties including scheduling delays, cost over runs and other events that may be beyond the control of the Company (See *Operational Risk Management - Development and Construction Risk*).

The Corporate Development Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Corporate Development group will begin construction or execute an acquisition agreement.

Each of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and satisfaction of the Company's investment return objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost Range (millions)[1]	Commercial Operation	PPA Term (Years)	Production (GW-hrs)
Projects in Construction						
Amherst Island Wind Project	Ontario	75	$ 320 - $ 350	2018	20	235
Great Bay Solar Project[2]	Maryland	75	169 - 188	2018	10	146
Total Projects in Construction		**150**	**$ 489 - $ 538**			**381**
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	$ 315 - $ 350	2019/20	25	813
Val-Eo Wind Project[3]	Quebec	24	60 - 70	2018	20	66
Turquoise Solar Project[4]	Nevada	10	25 - 31	2018		28
Total Projects in Development		**211**	**$ 400 - $ 451**			**907**
Total in Construction and Development		**361**	**$ 889 - $ 989**			**1,288**

1 Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

2 The total cost of the project is expected to be approximately U.S. $135 - U.S. $150 million. Two of the four Great Bay Solar sites achieved COD in December 2017 while the remaining two sites are expected to achieve COD in the first quarter of 2018.

3 All figures refer solely to Phase I of the Val-Eo Wind Project.

4 The Turquoise Solar Project will be included in the rate base of the Calpeco Electric System (see *Regulatory Proceedings*). The total cost of the project is expected to be approximately U.S. $20.0 - U.S. $25.0 million.

Projects Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating development project located in central Michigan and is constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group.

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

The project is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to a local electric distribution utility which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

The Liberty Power Group's initial interest in the project was via a 50% joint venture with the original developer along with an option to acquire the other 50% interest. On March 14, 2017, the Liberty Power Group exercised its option and purchased the remaining 50% interest in the project for U.S. $21.6 million.

The project qualified for U.S. federal production tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $166.6 million of financing for the project was received from tax equity investors in May 2017.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Liberty Power Group's 20 MW Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualified for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $12.3 million of financing for the project was sourced from a tax equity investor. The tax equity financing closed on February 28, 2017, following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

Liberty Power's interest in the project is via a 50% joint venture. Liberty Power has an option to acquire the other 50% interest, subject to certain adjustments, after COD and prior to January 15, 2019.

The total costs to complete the project are estimated at approximately $320.0 million to $350.0 million. The increase in the expected range of construction costs are primarily the result of additional winter construction days than previously anticipated. As the Company refines its operating model for post COD, it has identified new operational costs savings of approximately $10.0 million which are expected to be realized over the life of the project. Construction over the fall and winter months has focused primarily on building access roads, foundations and receiving turbine components.

Manufacturing of major equipment is now complete and turbine deliveries commenced in November 2017, with all turbines expected to be delivered by March 2018. To date, two turbines have been erected and the foundation for the power transformer housing is complete. The main power transformer was delivered to the site in early February 2018. A 115kV submarine cable was also successfully installed during 2017. Subject to receipt of ongoing construction-related permitting, construction is expected to be substantially completed in the second quarter of 2018.

Placement of construction debt closed in the fourth quarter of 2017 with a consortium of major financial institutions for a total commitment of $260.4 million.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project comprised of four sites located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

The project received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission and building permits from the Somerset County Building and Zoning Department. Both the balance of plant and high voltage engineering, procurement, and construction contracts have been executed.

The total costs to complete the project are estimated at approximately U.S. $135.0 million to U.S. $150.0 million. The project achieved partial completion in late 2017, producing revenue on 25 MW of the full site capacity. Approximately U.S. $59.0 million of the permanent project financing will come from tax equity investors. As of December 31, 2017, the project has received U.S $42.8 million in project funding, with the remaining expected to be received in the first half of 2018.

Projects in Development

Blue Hill Wind Project

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan.

The project is expected to generate 813.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA originally awarded in 2012 and amended in 2016.

The project requires development permits as well as final environmental approval. The Environmental Impact Study was completed and submitted to the Saskatchewan Ministry of Environment in the fourth quarter of 2017. Stakeholder engagement continued through 2017 with relevant government officials, NGOs, landowners and the community through open houses and in-person meetings.

The total costs to complete the project are estimated at approximately $315.0 million to $350.0 million. SaskPower recently completed an interim system impact study for the wind turbine generators, which was received in the fourth quarter of 2017. A geotechnical evaluation of the project site and existing infrastructure began in the fourth quarter of 2017, with results expected in early 2018. Preparation and submission of the development permit is expected in the first quarter of 2018.

Val-Éo Wind Project

The Val-Éo Wind Project is a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec. The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Liberty Power Group.

The Liberty Power Group has a 50% economic equity interest in the project. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $16.0 million.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely comprise ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

The total costs to complete Phase I of the project are estimated at approximately $60.0 million to $70.0 million. All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

Turquoise Solar Project

The Turquoise Solar project is a 10 MW solar powered electric generating development project located in Washoe County in Nevada.

The facility is comprised of 108,000 solar thin film panels on a tracker system and is being constructed on 110 acres of land. The Turquoise Solar Project is expected to generate 28 GW-hrs of energy per year and to be included in the rate base of the Calpeco Electric System as energy produced from the project will be consumed by the utility's customers (see *Regulatory Proceedings*).

The project has been approved by the California PUC, and mechanical completion is expected in the fourth quarter of 2018.

The total costs to complete the project are estimated at approximately U.S. $20.0 million to U.S. $25.0 million. The Liberty Utilities Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 30% of the permanent financing is expected to be funded by tax equity investors.

APUC: CORPORATE AND OTHER EXPENSES

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Corporate and other expenses:				
Administrative expenses	**$ 18.7**	$ 13.1	**$ 64.5**	$ 46.3
(Gain)/Loss on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition facility related to the Empire Acquisition	**—**	18.2	**17.6**	57.6
Interest expense	**42.4**	20.5	**185.0**	74.0
Interest, dividend, equity, and other income[1]	**(0.6)**	(3.1)	**(2.8)**	(5.3)
Other losses (gains)	**4.7**	(0.8)	**0.6**	(11.8)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Income tax expense	**38.0**	11.5	**95.2**	37.1

[1] Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (“U.S. Tax Reform” or the “Act”), was signed into law which resulted in significant changes to U.S. tax law. Key provisions of U.S. Tax Reform include the following:

- U.S. federal corporate income tax rate reduction from 35 per cent to 21 per cent effective January 1, 2018.
- The corporate alternative minimum tax (“AMT”) is eliminated effective January 1, 2018.
- The Base Erosion Anti-Abuse Tax (“BEAT”) is a new minimum tax computed each year and is generally the excess of (a) 10% of the taxpayer’s "modified taxable income" over (b) the taxpayer’s regular tax liability reduced by its tax credits.
- Other than for regulated utilities, interest deductibility is limited to 30 per cent of EBITDA from 2018 to 2021 and 30 per cent of EBIT after 2021.
- Other than for regulated utilities, immediate expensing of 100 per cent of the cost of new investments made in qualified depreciable assets after September 27, 2017.
- The production tax credit (the "PTC") of Section 45 of the Code and the investment tax credit (the "ITC") of Section 48 of the Code are left unchanged by the Act and the elimination of the AMT ensures that renewable energy tax credits will continue to be valuable to tax equity investors.
- The Act allows taxpayers until 2025 to offset any tax owed under the BEAT by 80% of the value of the PTCs and the ITCs for renewable energy projects.
- No change was made to the "continuous construction" requirement for determining when construction of a project commences.

As a result of these changes, the Company has remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. regulated and non-regulated businesses to reflect the new lower income tax rate as at December 31, 2017. This remeasurement resulted in a one-time non-cash accounting charge of $22.4 million and is recorded in the Company’s 2017 consolidated statement of operations.

Future Impacts

Beginning in 2018, the Company expects its effective tax rate on consolidated worldwide net income to be below 20%.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company believes that most of its U.S. holding company interest can be properly allocable in accordance with the Act to its U.S. regulated utilities and is therefore largely exempted from the interest deductibility limitations.

It is expected there will be no material changes to the Company's U.S. regulated utilities' future net earnings, specifically as it pertains to U.S. Tax Reform since normal rate making processes would see the lower income tax expense and amortization of the deferred tax revaluation regulatory liability offset by lower customer rates over time. However, the Company believes that all stakeholders are best served by dealing with U.S. Tax Reform within the context of a full regulatory rate case proceeding, where all factors that comprise rates can be considered including investments in rate base, recovery of operating costs, capital structure and cost of capital.

APUC views that going forward the lower tax rates can enable accelerated investment over time in our regulated utilities to deliver an improved customer experience and more reliable service with less of an impact on customer rates than would otherwise occur.

APUC continues to believe that with the provisions in the Act for PTCs and ITCs, between the Company's ability to absorb a part of the renewable energy tax credits in future years and anticipated future demand from third party tax equity investors wishing to avail themselves of renewable energy tax credits, the Company will be able to satisfy the tax equity financing component for its U.S. renewable energy projects over the next three to five years.

SEC Guidance

The U.S. Securities and Exchange Commission ("SEC") has issued guidance allowing registrants to record provisional amounts which may be adjusted as information over time becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with tax laws in effect prior to the enactment of the Act.

At December 31, 2017, APUC considers all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Given that APUC's utility businesses are regulated, the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional information emerge that affects current estimates during this one-year measurement period allowed for by the SEC, adjustments will be made to the provisional amounts as appropriate.

2017 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2017, administrative expenses totaled $18.7 million as compared to $13.1 million in the same period in 2016. The $5.6 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the three months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $nil as compared to $18.2 million in the same period in 2016.

For the three months ended December 31, 2017, interest expense totaled $42.4 million as compared to $20.5 million in the same period in 2016. The interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups.

For the three months ended December 31, 2017, other losses were $4.7 million as compared to gains of $0.8 million in the same period in 2016. The increase in current period losses is primarily attributable to an increase in regulatory liabilities in the LPSCo Water System resulting from ongoing regulatory proceedings.

For the three months ended December 31, 2017, gains on derivative financial instruments totaled $4.0 million as compared to $12.9 million in the same period in 2016. The increase in 2016 was primarily driven by mark-to-market gains on foreign currency derivatives.

For the three months ended December 31, 2017, an income tax expense of $38.0 million was recorded as compared to an income tax expense of $11.5 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2017 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2017, administrative expenses totaled $64.5 million as compared to $46.3 million in the same period in 2016. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the twelve months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $17.6 million as compared to $57.6 million in the same period in 2016 (see *note 14* in the financial statements).

For the twelve months ended December 31, 2017, interest expense totaled $185.0 million as compared to $74.0 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups. (See *Credit Facilities & Debt* and *note 9* in the financial statements).

For the twelve months ended December 31, 2017, other losses were $0.6 million as compared to a gain of $11.8 million in the same period in 2016. The prior period gains primarily resulted from: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see *note 18* in the financial statements) partially offset by (iii) the write-down of the Company's equity interest in natural gas development projects that have been canceled by the developer.

For the twelve months ended December 31, 2017, acquisition-related costs totaled $62.8 million as compared to $12.0 million in the same period in 2016. The increase is primarily attributable to the Empire Acquisition.

For the twelve months ended December 31, 2017, the gain on derivative financial instruments totaled $2.6 million as compared to a gain of $15.8 million in the same period in 2016. The gain in 2016 was due to market-to-market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as derivatives.

An income tax expense of $95.2 million was recorded in the twelve months ended December 31, 2017 as compared to an income tax expense of $37.1 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition, the tax effect related to the Mountain Water condemnation, and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

NON-GAAP FINANCIAL MEASURES

Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to U.S. GAAP consolidated net earnings.

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.8**	(0.8)	**3.2**	7.5
Income tax expense	**38.0**	11.5	**95.2**	37.1
Interest expense on convertible debentures and bridge financing	**—**	18.2	**17.6**	57.6
Interest expense on long-term debt and others	**42.4**	20.5	**185.0**	74.0
Other losses (gains)	**4.8**	(0.8)	**0.7**	(11.9)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on energy derivative contracts	**—**	—	**(0.7)**	(1.0)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Depreciation and amortization	**88.0**	52.6	**326.4**	186.9
Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9

HLBV represents the value of net tax attributes earned during the period primarily from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2017 amounted to $14.3 million and $67.8 million as compared to $13.6 million and $41.0 million during the same period in 2016.

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with U.S. GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on derivative financial instruments	**—**	—	**(0.7)**	(1.0)
Loss (gain) on long-lived assets, net	**1.5**	(0.8)	**(2.5)**	(3.3)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition financing	**—**	18.2	**17.6**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Other adjustments	**3.2**	—	**3.2**	—
U.S. Tax Reform adjustment [2]	**22.4**		**22.4**	
Adjustment for taxes related to above	**(0.6)**	(3.1)	**(3.9)**	(18.4)
Adjusted Net Earnings	**$ 85.9**	$ 51.4	**$ 292.1**	$ 161.6
Adjusted Net Earnings per share[1]	**$ 0.20**	$ 0.18	**$ 0.74**	$ 0.57

[1] Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

[2] Represents the one-time non-cash accounting charge related to the revaluation of U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

For the three months ended December 31, 2017, Adjusted Net Earnings totaled $85.9 million as compared to Adjusted Net Earnings of $51.4 million for the same period in 2016, an increase of $34.5 million. The increase in Adjusted Net Earnings for the three months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

For the twelve months ended December 31, 2017, Adjusted Net Earnings totaled $292.1 million as compared to Adjusted Net Earnings of $161.6 million for the same period in 2016, an increase of $130.5 million. The increase in Adjusted Net Earnings for the twelve months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the consolidated statement of operations and consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with U.S GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Cash flows from operating activities	**$ 169.8**	$ 121.9	**$ 457.8**	$ 287.9
Add (deduct):				
Changes in non-cash operating items	**(12.0)**	(46.7)	**74.0**	(3.7)
Production based cash contributions from non-controlling interests	**—**	0.6	**10.6**	11.2
Interest expense on convertible debentures and acquisition financing fees[1]	**—**	18.2	**9.3**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Cash generated from sale of long-lived assets	**—**	—	**—**	(8.6)
Adjusted Funds from Operations	**$ 159.1**	$ 96.4	**$ 614.5**	$ 356.4

1 Exclusive of deferred financing fees of $8.3 million.

For the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million as compared to Adjusted Funds from Operations of $96.4 million for the same period in 2016, an increase of $62.7 million.

For the twelve months ended December 31, 2017, Adjusted Funds from Operations totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million for the same period in 2016, an increase of $258.1 million.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES[1]

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Liberty Power Group:				
Maintenance	**$ 4.0**	$ 21.0	**$ 18.1**	$ 58.6
Investment in Capital Projects[1]	**17.1**	169.0	**592.7**	538.1
	$ 21.1	$ 190.0	**$ 610.8**	$ 596.7
Liberty Utilities Group:				
Rate Base Maintenance	**$ 58.4**	$ 27.0	**$ 222.1**	$ 102.7
Rate Base Acquisition	**—**	—	**2,764.4**	345.3
Rate Base Growth	**89.8**	101.0	**328.7**	163.4
	148.2	128.0	**3,315.2**	611.4
Total Capital Expenditures	**$ 169.3**	$ 318.0	**$ 3,926.0**	$ 1,208.1

1 Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the Company.

2017 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $21.1 million as compared to $190.0 million during the same period in 2016. The capital expenditures include the ongoing construction of the Great Bay Solar Project, additional investment into the Amherst Wind Project, and ongoing maintenance capital at existing operating sites. Capital expenditures in the same quarter last year included the purchase of approximately $75 million of turbine components ("Safe Harbor Turbines"), costs of rebuilding the Donnaconna Hydro Facility dam, and ongoing development costs related to the investment and build of the Deerfield Wind, Amherst Wind, and Great Bay Solar Projects.

During the three months ended December 31, 2017, the Liberty Utilities Group invested $148.2 million in capital expenditures as compared to $128.0 million during the same period in 2016. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Capital expenditures in the same quarter last year included investments into the Luning Solar Facility and further development of Phase I of the North Lake Tahoe transmission project to upgrade the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2017 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $610.8 million as compared to $596.7 million during the same period in 2016. The capital expenditures include the acquisition of the remaining outstanding interest in the Deerfield Wind Facility, completion of the Bakersfield II Solar Facility, upgrade of the Tinker Transmission Facility, and ongoing development costs related to the investment and construction of the Amherst Wind and Great Bay Solar Projects.

During the twelve months ended December 31, 2017, the Liberty Utilities Group invested $3.3 billion in capital expenditures as compared to $611.4 million during the same period in 2016. The increase in capital expenditures is primarily due to the Empire Acquisition in January 2017 (U.S. $2.4 billion) and completion of the Luning Solar Facility located in Mineral County, Nevada in February 2017 (U.S. $84.9 million). In the prior year, the Liberty Utilities Group completed the acquisition of the Park Water System in January 2016, further development of Phase I of the North Lake Tahoe transmission project, and reliability enhancements, improvements and replenishment opportunities at the utility systems served.

2018 Capital Investments

In 2018, the Company plans to spend between $1.2 billion and $1.4 billion on capital investment opportunities. Actual expenditures during the course of 2018 may vary due to timing of various project investments and the realized U.S. dollar exchange rate.

Expected 2018 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Liberty Power Group:			
Maintenance	$ 30.0	-	$ 40.0
Investment in Capital Projects	120.0	-	150.0
Total Liberty Power Group:	$ 150.0	-	$ 190.0
Liberty Utilities Group:			
Rate Base Maintenance	$ 210.0	-	$ 230.0
Rate Base Growth	140.0	-	180.0
Total Liberty Utilities Group:	$ 350.0	-	$ 410.0
Investment in Atlantica[1]	$ 700.0		$ 800.0
Total 2018 Capital Investments	**$ 1,200.0**	**-**	**$ 1,400.0**

[1] See *Major Highlights*

The Liberty Power Group intends to spend between $150.0 million - $190.0 million over the course of 2018 to develop or further invest in capital projects, primarily in relation to the final development of the Great Bay Solar and Amherst Island Wind Projects. Additionally, the Liberty Power Group plans to spend $30.0 million - $40.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

The Liberty Utilities Group intends to spend between $350.0 million - $410.0 million over the course of 2018 in an effort to improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects entail spending capital for structural improvements, specifically in relation to drilling and equipping aquifers, main replacements, and reservoir pumping stations.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Power Group, and the Liberty Utilities Group to manage the liquidity and working capital requirements of each division (collectively the “Bank Credit Facilities”).

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2017:

	As at December 31, 2017				As at Dec 31, 2016
(all dollar amounts in $ millions)	Corporate	Liberty Power	Liberty Utilities	Total	Total
Committed facilities	$ 165.0	$ 714.9	$ 501.8	**$ 1,381.7**	$ 773.8
Funds drawn on facilities	—	(44.8)	(16.3)	**(61.1)**	(242.9)
Letters of credit issued	(13.9)	(136.3)	(24.5)	**(174.7)**	(234.9)
Liquidity available under the facilities	**151.1**	**533.8**	**461.0**	**1,145.9**	296.0
Cash on hand				**54.6**	110.4
Total Liquidity and Capital Reserves	**$ 151.1**	**$ 533.8**	**$ 461.0**	**$ 1,200.5**	$ 406.4

As at December 31, 2017, the Company's $165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.9 million of outstanding letters of credit. The facility matures on November 19, 2018 and is subject to customary covenants.

On December 21, 2017, the Company entered into a U.S. $600.0 million term credit facility with two Canadian banks maturing on December 21, 2018. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the company drew U.S. $600.0 million under this facility.

As at December 31, 2017, the Liberty Power Group's committed bank lines consisted of a U.S. $500.0 million senior unsecured syndicated revolving credit facility and a $87.6 million letter of credit facility (Cdn $50.0 million and U.S. $30.0 million). As at December 31, 2017, the group had drawn $44.8 million and had $136.3 million in outstanding letters of credit. The facilities mature on October 6, 2022 and October 30, 2018, respectively. Subsequent to year-end, on February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200.0 million and extended the maturity to January 31, 2021. The expansion of both the revolving credit and letter of credit facility further increases the Liberty Power Group's ability to support the cash needs of its development portfolio.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200.0 million senior unsecured syndicated revolving credit facility at the holding company ("Liberty Credit Facility") and a U.S. $200.0 million revolving credit facility at Empire ("Empire Credit Facility"). The credit facilities mature on September 30, 2018 and October 20, 2019, respectively. The Empire Credit Facility is used primarily as a backstop to commercial paper issued by Empire. As at December 31, 2017, the Liberty Utilities Group had drawn a total of $16.3 million (U.S. $13.0 million) and had $24.5 million (U.S. $19.5 million) of outstanding letters of credit. Subsequent to year-end on February 23, 2018, the Liberty Utilities Group increased commitments under the Liberty Credit Facility to U.S. $500.0 million and extended the maturity to 2023. In conjunction with the increase to the Liberty Credit Facility, the Empire Credit Facility was canceled. The Liberty Credit Facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire as required.

On February 9, 2016, in connection with the Empire Acquisition, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. On December 30, 2016, the Company drew U.S. $1,336.4 million on the Acquisition Facility in connection with the closing of the Empire Acquisition. The Acquisition Facility was fully repaid in the first quarter of 2017 from proceeds received from the final installment payment, the Liberty Private Placement (discussed below) and general corporate funds.

Long Term Debt

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750.0 million of senior unsecured notes ("Liberty Private Placement") in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "*Interest Rate Risk*"). Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group is 3.6%. The proceeds of the offering were applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at December 31, 2017, the weighted average tenor of APUC's total long term debt is approximately 12 years with an average interest rate of 4.6%.

Convertible Unsecured Subordinated Debentures

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures of APUC.

All Debentures were sold on an instalment basis at a price of $1,000 dollars per debenture, of which $333 dollars was paid on the closing of the Offering and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of the Empire Acquisition (the "Final Instalment Date"), at which time each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

The final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of the Acquisition Facility. As at March 6, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

Contractual Obligations

Information concerning contractual obligations as of December 31, 2017 is shown below:

(all dollar amounts in $ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1]	**$ 3,826.1**	$ 279.7	$ 570.1	$ 645.0	$ 2,331.3
Convertible debentures	**1.2**	—	—	—	1.2
Advances in aid of construction	**78.6**	1.5	—	—	77.1
Interest on long-term debt obligations	**2,006.2**	172.7	307.5	250.8	1,275.2
Purchase obligations	**501.9**	501.9	—	—	—
Environmental obligations	**72.0**	7.8	18.9	5.4	39.9
Derivative financial instruments:					
Cross currency swap	**72.0**	4.4	8.1	64.7	(5.2)
Interest rate swap	**10.6**	10.6	—	—	—
Currency forward	**0.4**	0.4	—	—	—
Energy derivative and commodity contracts	**3.4**	2.3	1.0	—	0.1
Purchased power	**527.4**	74.0	98.3	100.7	254.4
Gas delivery, service and supply agreements	**369.2**	91.4	118.7	61.6	97.5
Service agreements	**673.9**	47.7	95.7	95.4	435.1
Capital projects	**58.3**	41.1	17.1	0.1	—
Operating leases	**270.0**	9.6	17.3	18.1	225.0
Other obligations	**155.3**	45.0	—	—	110.3
Total Obligations	**$ 8,626.5**	**$ 1,290.1**	**$ 1,252.7**	**$ 1,241.8**	**$ 4,841.9**

[1] Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2017, APUC had 431,765,935 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2017, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of common shares of APUC. As at December 31, 2017, 94,049,616 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2017, 3,905,848 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 12, 2018, an additional 1,063,572 common shares were issued under the Reinvestment Plan.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2017, APUC recorded $10.8 million in total share-based compensation expense as compared to $5.7 million for the same period in 2016. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were $2.8 million and $8.5 million, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2017, the Company granted 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $12.82, the market price of the underlying common share at the date of grant. In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of $7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2017, a total of 6,738,856 options are issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2017, the Company granted (including dividends and performance adjustments) 811,974 PSUs to executives and employees of the Company. During the year, the Company settled 374,973 PSUs, of which 183,035 PSUs were exchanged for common shares issued from treasury and 191,938 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2017, a total of 60,961 PSUs were forfeited.

As at December 31, 2017, a total of 955,028 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2017, the Company issued 69,243 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2017, a total of 293,906 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2017, the Company issued 283,523 common shares to employees under the ESPP.

As at December 31, 2017, a total of 779,553 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Emera Inc.

An executive at Emera Inc. ("Emera") was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4.4 million as compared to U.S. $10.2 million during the same period in 2016. The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during 2017 amounts to U.S. $1.0 million as compared to U.S. $3.9 million during the same period in 2016. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.

In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in the second quarter of 2017, with the final completion of the contract work in the fourth quarter of 2017. The total cost of the contract was $9.5 million. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1.5 million included in accruals in 2017 as compared to U.S. $0.8 million during the same period in 2016 related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $6.0 million in 2017 as compared to $3.3 million during the same period in 2016.

Trafalgar

In 2016, the Company received U.S. $10.1 million in proceeds from the settlement of the Trafalgar matter and paid U.S. $2.9 million to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

ENTERPRISE RISK MANAGEMENT

The Corporation is subject to a number of risks and uncertainties. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation's business could be materially different from what is anticipated. The description of risks below does not include all possible risks.

An enterprise risk management, or "ERM", framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as the Corporation's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee on a quarterly basis.

Risks are evaluated consistently across the organization using a common risk scoring matrix to assess impact and likelihood. Financial, reputational, and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of the Corporation's strategic and business plans.

The development and execution of risk treatment plans for the organization's top risks are actively monitored by the Company's senior leadership team and Board of Directors. The Corporation's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for key risks. Audit findings are discussed with business owners and reported to the Audit Committee of the Board of Directors on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, the Corporate Governance and Risk Committees, and the Board of Directors of the Corporation for consideration.

The Corporation's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that the Corporation's risk appetite is thoroughly considered in decision-making across the organization

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is set out in the Company's most recent AIF available on SEDAR.

Treasury Risk Management

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's.

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries' issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long-term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

The Company is not adopting or endorsing such ratings, and such ratings do not indicate APUC's assessment of its own ability to pay the interest or principal of debt securities it issues. The Company is providing such ratings only to assist with the assessment of future risks and effects of ratings on the Company's financing costs.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

Capital Markets and Liquidity Risk

As of December 31, 2017, the Company had approximately $3,864.5 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favorable terms may be affected by the Company's financial and operational performance, and by financial market disruptions or other factors outside the control of the Company.

In addition, the Company may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the degree of the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; limit the Company's ability to declare dividends on its common shares; require the Company to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose the Company to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place the Company at a competitive disadvantage compared to its competitors that have less debt; make the Company vulnerable to any downturn in general economic conditions; and render the Company unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favorable than the current terms, the ability of the Company to declare dividends may be adversely affected.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flows in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to significant interest rate risk in the short to medium term time horizon.

Borrowings subject to variable interest rates can vary significantly from month to month, quarter to quarter and year to year. APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Based on amounts outstanding as at December 31, 2017, the impact to interest expense from changes in interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had $44.8 million outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $0.4 million annually;
- The Liberty Utilities Group's revolving credit facilities are subject to a variable interest rate and had $16.3 million outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $7.0 million (U.S. $5.6 million) outstanding at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually.
- The Corporate Term Facility is subject to a variable interest rate and had $169.4 million (U.S. $135.0 million) outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 million annually;

To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Liberty Power Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.

Foreign Currency Risk

Currency fluctuations may affect the Canadian dollar equivalent cash flows that APUC realizes from its consolidated operations because a significant portion of the Company's revenues are generated through APUC subsidiary businesses which sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 93% of Adjusted EBITDA in 2017 and 93% of cash flow from operations is generated in U.S. dollars.

APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $82.3 million ($0.22 per share) on an annual basis. In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

APUC may enter into derivative contracts to hedge all or a portion of currency exchange rate exposure that is transactional in nature and where a natural economic hedge does not exist. To the extent that the Company does enter into currency hedges, the Company may not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts.

Effective the first quarter of 2018, APUC will begin to report its results in U.S. dollars.

Tax Risk and Uncertainty

The Company is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which APUC does business could adversely affect the Company's results from operations, our return to shareholders, and cash flow.

The Company cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Company, including with respect to claimed expenses and the cost amount of the Company's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or APUC is unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that APUC is committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Company from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Company (See *U.S. Tax Reform*).

Credit/Counterparty Risk

APUC and its subsidiaries, through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments, are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

Liberty Power Group's revenues are approximately 15% of total Company revenues. Approximately 94% of the Liberty Power Group's revenues are earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. The following chart sets out the Liberty Power Group's customers representing greater than 5% of total Liberty Power Group revenues and their credit ratings:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percentage of Liberty Power Group Revenue
PJM Interconnection LLC	Aa2	$ 31.8	11.2%
Manitoba Hydro	Aa2	30.3	10.7%
Hydro Quebec	Aa2	29.1	10.3%
Commonwealth Edison	A3	26.4	9.3%
Xcel Energy	A3	24.2	8.6%
Pacific Gas and Electric Company	A3	24.1	8.5%
Wolverine Power Supply	A	23.5	8.3%
Ontario Electricity Financial Corporation	Aa2	22.9	8.1%
Electric Reliability Council of Texas (ERCOT)	Aa3	16.7	5.9%
Connecticut Light and Power	Baa1	16.2	5.7%
Total		**$ 245.2**	

[1] Ratings by DBRS, Moody's, or S&P.

The remaining revenue of the Company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $10.4 million which is spread over approximately 160,000 connections, resulting in an average outstanding balance of approximately U.S. $70 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $21.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $99.9 million. The natural gas and electrical utilities both derive over 84% of their revenue from residential customers.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Liberty Power Group is unable to perform, the Liberty Power Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

Market Price Risk

The Liberty Power Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Liberty Power Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Liberty Power Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Liberty Power Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the Liberty Power Group along with residual exposures to the market are detailed below:

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

A second hedge for the Sandy Ridge Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 73% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 42,000 MW-hrs annually.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

A second hedge for the Minonk Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 72% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 189,000 MW-hrs annually.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Liberty Power Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2017, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,080 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $0.5 million for the year.

Commodity Price Risk

The Liberty Power Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 181,000 MW-hrs in fiscal 2018, of which 170,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 37,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 181,000 MW-hrs. The risk associated with the expected market purchases of 37,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 20% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $86 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

The Calpeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The Calpeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The Calpeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the Calpeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the Georgia PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 58% of its 2017 generation fuel supply need through coal. Approximately 97% of its 2017 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts and inventory on hand satisfy approximately 56% of anticipated fuel requirements for 2018 for the Asbury Coal Facility.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel adjustment clause and PGA filings and are embedded in the approved rates in such filings.

OPERATIONAL RISK MANAGEMENT

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, natural disasters, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Liberty Power Group's hydro assets utilize dams to pond water for generation and if the dams fail/breach potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Liberty Power Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions, which will lower wind levels below our PPA and hedge minimum production levels. The wind units can experience failures in the turbine blades or in the supporting towers. Production risks associated with the wind turbine generators failures is mitigated by properly maintaining the units, using long term maintenance agreements with the turbine O&Ms which provide for regular inspections and maintenance of property, and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Liberty Power Group's Thermal Energy Division uses natural gas and oil, and produces exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the thermal facilities are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged in part by long term purchases.

All of the Liberty Power Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Liberty Utilities Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Liberty Utilities Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down, with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Liberty Utilities Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance, an active Enterprise Risk Management program and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The Liberty Utilities Group operates in 12 different states and therefore is subject to regulation from 12 different regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Liberty Utilities Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, the Act reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates will have a significant impact on the financial operations and regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. The Liberty Utilities Group is working with stakeholders to understand the full implications and impact of the new law. Liberty believes that customers will be best served by dealing with Tax Reform within the context of a full regulatory rate case, where all factors that comprise rates can be considered.

Condemnation Expropriation Proceedings

The Liberty Utilities Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

Mountain Water Condemnation Proceedings

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("Carlyle"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. $88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have appealed certain elements of the final order of condemnation including, among other issues, recovery of post-summons interest and attorney's fees.

Apple Valley Condemnation Proceedings

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to require a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act ("CEQA") lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Apple Valley's CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case on March 6, 2018 to potentially set a trial date on the first phase of the condemnation action.

Acquisition Risk

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

When acquisitions occur, significant demands can be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Joint Venture Investment Risk

Certain development and operating entities that the Company has interest in are jointly owned with third parties. The Company may not have the sole discretion or ability to affect the management or operations at such facilities and thereby may not be able to make determinations on how to manage these facilities in light of changing economic circumstances. A divergence in the interests of the Company and the co-owners could negatively impact the realization of the Company's investment in the joint venture business, which may have a disproportionate economic impact relative to the Company's investment.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Liberty Utilities Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Liberty Utilities Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Liberty Utilities Group expects to be allowed to earn a return on such investment.

In conjunction with acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas mains when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

Cycles and Seasonality

Liberty Power Group

The Liberty Power Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Liberty Power Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Liberty Utilities Group

The Liberty Utilities Group’s demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group’s demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Liberty Utilities Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 4 of 12 states representing approximately 25% of customers. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. The Liberty Utilities Group is presently seeking weather related decoupling mechanism for its utilities in Missouri and New Hampshire.

Development and Construction Risk

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company’s overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

Risks Specific to Renewable Generation Projects:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal and regulatory proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

See further discussion of claims made by or against APUC or its subsidiaries in *Regulatory Risk*.

Cybersecurity Risk

The Company's information technology systems may be vulnerable to potential risks from cybersecurity attacks. Attacks can be caused by malware, viruses, email attachments, acts of war or terrorism and can originate from individuals from both inside and outside the organization. An attack could result in service disruptions, system failures, the disclosure of personal customer and employee information, and could lead to an adverse effect on the Company's financial performance. A breach of personal or confidential information may also occur as a result of non-cyber means, such as breach of physical security. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

The Company mitigates these risks by maintaining a cybersecurity program that is overseen by the Board of Directors, and executed by a cross functional management team. The program is intended to provide adequate controls for the appropriate protection of critical business systems. These controls have been put into place to mitigate potential risks, and to improve the organization’s capability to respond and recover from any potential cyber incident.

Energy Consumption and Advancement in Technologies Risk

The Liberty Utilities Group's operations are subject to changes in demand for energy which are impacted by general economic conditions, customer's focus on energy efficiency, and advancements in new technologies.

The Liberty Utilities Group is actively involved in working with governments and customers to ensure these changes in consumption do not negatively impact the services provided. Furthermore, through its strategic initiatives the Liberty Utilities Group is constantly looking for ways to maintain the Company's competitive advantage.

Uninsured Risk

The Company maintains insurance for accidental loss and potential liabilities to third parties. However, there are certain elements of the Liberty Utilities Group's regulated utilities that are not fully insured as the cost of the coverage is not economically viable. In the event that a liability event or loss is not covered through insurance the Liberty Utilities Group would apply to their respective regulator to request recovery through increased customer rates. Cost recovery through this mechanism is subject to regulatory approval and is therefore uncertain.

Insurance coverage for the rest of the Company is also subject to policy conditions and exclusions, coverage limits, and various deductibles, and not all types of liabilities and losses may be covered by insurance, in which case the Company may be financially exposed.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2017:

(all dollar amounts in $ millions except per share information)	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017	4th Quarter 2017
Revenue	$ 557.9	$ 453.2	$ 443.3	$ 523.4
Net earnings attributable to shareholders	26.0	47.7	59.4	60.0
Net earnings per share	0.07	0.12	0.15	0.14
Adjusted Net Earnings	88.1	53.3	64.9	85.9
Adjusted Net Earnings per share	0.25	0.13	0.16	0.20
Adjusted EBITDA	254.8	197.6	197.5	233.4
Total assets	10,880.7	10,528.6	10,306.7	10,533.6
Long term debt[1]	4,773.6	4,418.0	4,435.1	3,864.5
Dividend declared per common share	$ 0.15	$ 0.16	$ 0.15	$ 0.15

	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016
Revenue	$ 341.7	$ 222.8	$ 221.3	$ 310.2
Net earnings attributable to shareholders	42.0	24.8	17.7	46.3
Net earnings per share	0.15	0.08	0.06	0.16
Adjusted Net Earnings	56.1	30.9	26.6	51.4
Adjusted Net Earnings per share	0.21	0.11	0.09	0.18
Adjusted EBITDA	147.9	99.2	91.4	138.3
Total assets	5,615.5	5,555.0	6,020.8	8,249.5
Long term debt[1]	2,214.5	2,199.9	2,380.8	4,272.0
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14

[1] Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $221.3 million and $557.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.7 million and $60 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2017, under the supervision of and with the participation of APUC's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2017, APUC's disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by APUC in reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

During the year ended December 31, 2017, the Company acquired Empire. Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company's internal control over financial reporting. The financial information for this acquisition is included in this MD&A and in *note 3* to the consolidated financial statements. As permitted by National Instrument 52-109 and the SEC, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and approximately 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of APUC.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

For the twelve months ended December 31, 2017, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. The Company continues to implement its internal control structure over the operations of the acquired business discussed above.

INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

Due to its inherent limitations, disclosure controls and procedures or internal control over financial reporting may not prevent or detect all misstatements based on error of fraud. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, the measurement of deferred taxes and the recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies and new accounting standards are discussed in *notes 1* and *2* to the consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

A recoverability analysis was performed in 2017 for wind generating assets operating without a PPA and in 2016 for wind and small hydro generating assets without a PPA. No impairment provision was required in 2017 or 2016. A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2017 and 2016, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

Measurement of Deferred Taxes

On December 22, 2017, the U.S. government enacted the Tax Cuts and Jobs Act (the "Act"). The Act made broad and complex changes to the U.S. tax code which impacted 2017 including, but not limited to, reducing the U.S. federal corporate tax rate from 35% to 21% and introducing 100% expensing for certain capital expenditures, excluding regulated utilities, made after September 27, 2017. Management's judgment is required to measure the deferred taxes assets and liabilities at the enactment date based on these changes. Where requirements of the implementation of the new Act are incomplete, management uses judgments and assumptions to calculate a reasonable provisional amount to include in the Company's financial statements.

Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Although at this time Management considers it more likely than not that it will have sufficient taxable income to realize the deferred tax assets, there can be no assurance that the company will generate sufficient taxable income in the future to utilize these deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. Management's assessment has been impacted by the tax reform discussed above.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Liberty Utilities Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The Financial Accounting Standards Board ("FASB") issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. The Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company intends to adopt the new revenue recognition standard using the modified retrospective method effective January 1, 2018.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management’s judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management’s judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC’s results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2017) recently released by the Society of Actuaries adjusted to reflect the 2017 Social Security Administration ultimate improvement rates.

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, for reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this Accounting Standards Update ("ASU"), the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2017 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

	2017 Pension Plans		2017 OPEB Plans	
(all dollar amounts in $ millions)	Accrued Benefit Obligation	Net Periodic Pension Cost	Accumulated Postretirement Benefit Obligation	Net Periodic Postretirement Benefit Cost
Discount Rate				
1% increase	(65.6)	(4.4)	(31.5)	(1.9)
1% decrease	81.1	6.7	39.7	2.1
Future compensation rate				
1% increase	0.2	1.5	—	—
1% decrease	(0.2)	(1.3)	—	—
Expected return on plan assets				
1% increase	—	(4.5)	—	(1.4)
1% decrease	—	4.5	—	1.4
Life expectancy				
10% increase	38.0	3.3	19.7	1.6
10% decrease	(39.9)	(2.8)	(18.8)	(1.8)
Health care trend				
1% increase	—	—	38.0	4.3
1% decrease	—	—	(30.1)	(3.3)

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management’s estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC’s critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2017.

During the year ended December 31, 2017, APUC acquired The Empire District Electric Company and its subsidiaries ("Empire"). The financial information for this acquisition is included in note 3(a) to the consolidated financial statements. As permitted by National Instrument 52-109 and published guidance of the U.S. Securities and Exchange Commission (SEC), management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Empire, which are included in the 2017 consolidated financial statements of Algonquin Power and Utilities Corp. and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues for the year then ended.

March 7, 2018

/s/ Ian Robertson	/s/ David Bronicheski
Chief Executive Officer	Chief Financial Officer

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income/(loss), equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements").

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Report on internal control over financial reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 7, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2013.

Toronto, Canada

March 7, 2018

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on Internal Control over Financial Reporting

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, Algonquin Power & Utilities Corp. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information and our report dated March 7, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated under the heading Internal Controls over Financial Reporting in Management's Report, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Empire District Electric Corp. and its subsidiaries ("Empire"), which are included in the 2017 consolidated financial statements of the Company and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power and Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Empire.

/s/ Ernst & Young LLP

Toronto, Canada

March 7, 2018

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,550	$ 110,417
Accounts receivable, net (note 4)	306,872	189,658
Fuel and natural gas in storage (note 1(h))	55,718	21,625
Supplies and consumables inventory	56,546	15,568
Regulatory assets (note 7)	83,508	48,440
Prepaid expenses	38,896	26,562
Derivative instruments (note 25)	20,196	76,631
Other assets (note 12)	8,919	2,951
	625,205	491,852
Property, plant and equipment, net (note 5)	7,909,493	4,889,946
Intangible assets, net (note 6)	64,108	64,989
Goodwill (note 6)	1,196,234	306,641
Regulatory assets (note 7)	467,626	243,524
Derivative instruments (note 25)	67,888	74,553
Long-term investments (note 8)	84,467	105,433
Deferred income taxes (note 20)	76,972	30,005
Restricted cash (note 1(f))	19,995	2,026,183
Other assets (note 12)	21,647	16,334
	$10,533,635	$ 8,249,460

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 150,426	$ 90,592
Accrued liabilities	351,441	308,318
Dividends payable (note 17)	63,283	38,973
Regulatory liabilities (note 7)	47,278	47,769
Long-term debt (note 9)	15,511	10,075
Other long-term liabilities and deferred credits (note 13)	57,586	43,157
Derivative instruments (note 25)	17,721	4,178
Other liabilities	4,359	3,487
	707,605	546,549
Long-term debt (note 9)	3,847,785	3,903,340
Convertible debentures (note 14)	1,218	358,619
Regulatory liabilities (note 7)	677,778	134,965
Deferred income taxes (note 20)	499,819	288,139
Derivative instruments (note 25)	68,769	104,647
Pension and other post-employment benefits obligation (note 10)	210,994	147,845
Other long-term liabilities (note 13)	285,106	232,449
Preferred shares, Series C (note 11)	17,396	17,552
	5,608,865	5,187,556
Redeemable non-controlling interest (note 19)	52,128	29,434
Equity:		
Preferred shares (note 15(b))	213,805	213,805
Common shares (note 15(a))	3,713,037	1,972,203
Additional paid-in capital	43,204	38,652
Deficit	(617,836)	(556,024)
Accumulated other comprehensive income (note 16)	56,820	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	3,409,030	1,923,563
Non-controlling interests (note 19)	756,007	562,358
Total equity	4,165,037	2,485,921
Commitments and contingencies (note 23)		
Subsequent events (notes 9 and 15(a)(iii))		
	$10,533,635	$ 8,249,460

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2017	**2016**
Revenue		
Regulated electricity distribution	$ 989,221	$ 228,097
Regulated gas distribution	493,208	405,735
Regulated water reclamation and distribution	181,851	181,655
Non-regulated energy sales	282,558	243,149
Other revenue	30,971	37,382
	1,977,809	1,096,018
Expenses		
Operating expenses	598,658	333,001
Regulated electricity purchased	288,183	119,825
Regulated gas purchased	184,523	142,003
Regulated water purchased	12,310	12,227
Non-regulated energy purchased	25,384	21,260
Administrative expenses	64,466	46,349
Depreciation and amortization	326,447	186,899
Loss (gain) on foreign exchange	373	(436)
	1,500,344	861,128
Operating income	477,465	234,890
Interest expense on long-term debt and others	184,993	73,962
Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 14)	17,638	57,630
Interest, dividend, equity and other income	(11,989)	(10,573)
Other losses (gains) (note 23(a))	632	(11,818)
Acquisition-related costs	62,777	12,028
Gain on derivative financial instruments (note 25(b)(iv))	(2,626)	(15,849)
	251,425	105,380
Earnings before income taxes	226,040	129,510
Income tax expense (note 20)		
Current	9,908	8,461
Deferred	85,286	28,675
	95,194	37,136
Net earnings	130,846	92,374
Net effect of non-controlling interests (note 19)	62,248	38,550
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 193,094	$ 130,924
Series A and D Preferred shares dividend (note 17)	10,400	10,400
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 182,694	$ 120,524
Basic net earnings per share (note 21)	$ 0.48	$ 0.44
Diluted net earnings per share (note 21)	$ 0.47	$ 0.44

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2017	**2016**
Net earnings	$ 130,846	$ 92,374
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax recovery of $219 and $nil, respectively (notes 1(v), 25(b)(iii) and 25(b)(iv))	(256,067)	(67,855)
Change in fair value of cash flow hedges, net of tax expense of $756 and $18,109, respectively (note 25(b)(ii))	1,909	26,754
Change in value of available-for-sale investments	(141)	213
Change in pension and other post-employment benefits, net of tax expense of $717 and $1,433, respectively (note 10)	525	2,252
Other comprehensive loss, net of tax	(253,774)	(38,636)
Comprehensive (loss) income	(122,928)	53,738
Comprehensive loss attributable to the non-controlling interests	(117,915)	(45,376)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ (5,013)	$ 99,114

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2017

	Algonquin Power & Utilities Corp. Shareholders						
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2016	$1,972,203	$213,805	$ 38,652	$ (556,024)	$ 254,927	$562,358	$ 2,485,921
Net earnings (loss)	—	—	—	193,094	—	(62,248)	130,846
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	13,400	13,400
Other comprehensive loss	—	—	—	—	(198,107)	(55,667)	(253,774)
Dividends declared and distributions to non-controlling interests	—	—	—	(205,439)	—	(5,055)	(210,494)
Dividends and issuance of shares under dividend reinvestment plan (note 15(a)(iii))	47,470	—	—	(47,470)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 15(a)(i))	558,083	—	—	—	—	—	558,083
Common shares issued upon conversion of convertible debentures (note 14)	1,114,688	—	—	—	—	—	1,114,688
Common shares issued pursuant to share-based awards (note 15(c))	20,593	—	(6,527)	(1,997)	—	—	12,069
Share-based compensation (note 15(c))	—	—	11,079	—	—	—	11,079
Contributions received from non-controlling interests (notes 3(c), 3(g) and 8(b))	—	—	—	—	—	303,219	303,219
Balance, December 31, 2017	$3,713,037	$213,805	$ 43,204	$ (617,836)	$ 56,820	$756,007	$ 4,165,037

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2016

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864
Net earnings (loss)	—	—	—	—	130,924	—	(38,550)	92,374
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	—	4,952	4,952
Other comprehensive income	—	—	—	—	—	(31,810)	(6,826)	(38,636)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(125,696)	—	(3,926)	(129,622)
Dividends and issuance of shares under dividend reinvestment plan	33,862	—	—	—	(33,862)	—	—	—
Common shares issued upon conversion of subscription receipts	110,503	—	(110,503)	—	—	—	—	—
Common shares issued pursuant to share-based awards (note 15(c))	18,944	—	—	(5,505)	(4,274)	—	—	9,165
Share-based compensation	—	—	—	5,916	—	—	—	5,916
Contributions received from non-controlling interests	—	—	—	—	—	—	12,752	12,752
Non-controlling interest of acquired operating entity	—	—	—	—	—	—	237,156	237,156
Balance, December 31, 2016	$1,972,203	$213,805	$ —	$ 38,652	$ (556,024)	$ 254,927	$562,358	$2,485,921

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2017	2016
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 130,846	$ 92,374
Adjustments and items not affecting cash:		
Depreciation and amortization	329,273	195,751
Deferred taxes	85,286	28,675
Unrealized loss (gain) on derivative financial instruments	1,764	(18,689)
Share-based compensation expense	10,630	5,916
Cost of equity funds used for construction purposes	(3,014)	(2,774)
Pension and post-employment contributions in excess of expense	(26,893)	(13,491)
Non-cash revenue and other income	—	(10,467)
Distributions received from equity investments, net of income	3,141	653
Write-down of long-lived assets	789	6,259
Changes in non-cash operating items (note 24)	(74,026)	3,704
	457,796	287,911
Financing Activities		
Increase in long-term debt	1,838,035	2,399,009
Decrease in long-term debt	(3,131,717)	(68,423)
Issuance of convertible debentures, net of costs	743,881	357,694
Cash dividends on common shares	(170,199)	(118,145)
Dividends on preferred shares	(10,400)	(10,400)
Contributions from non-controlling interests	333,395	13,468
Production-based cash contributions from non-controlling interest	10,622	9,454
Distributions to non-controlling interests	(4,135)	(4,307)
Issuance of common shares, net of costs	556,634	1,526
Proceeds from settlement of derivative assets	48,381	—
Proceeds from exercise of share options	12,761	18,461
Shares surrendered to fund withholding taxes on exercised share options	(4,401)	(5,218)
Increase in other long-term liabilities	33,030	6,486
Decrease in other long-term liabilities	(8,751)	(4,269)
	247,136	2,595,336
Investing Activities		
Decrease (increase) in restricted cash	2,011,204	(2,007,732)
Acquisitions of operating entities	(2,047,401)	(432,699)
Divestiture of operating entity	111,043	—
Additions to property, plant and equipment	(740,023)	(405,743)
Increase in other assets	(9,122)	(20,501)
Receipt of principal on notes receivable	—	319,160
Increase in long-term investments	(82,449)	(347,901)
	(756,748)	(2,895,416)
Effect of exchange rate differences on cash	(4,051)	(2,231)
Decrease in cash and cash equivalents	(55,867)	(14,400)
Cash and cash equivalents, beginning of year	110,417	124,817
Cash and cash equivalents, end of year	$ 54,550	$ 110,417

Supplemental disclosure of cash flow information:	**2017**	**2016**
Cash paid during the year for interest expense	$ 198,045	$ 131,783
Cash paid during the year for income taxes	$ 11,377	$ 13,369
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 141,708	$ 146,301
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 51,178	$ 35,409
Issuance of common shares upon conversion of convertible debentures	$ 1,102,304	$ —
Issuance of common shares upon conversion of subscription receipts	$ —	$ 110,503
Acquisition of equity investments in exchange for loan receivable and payable	$ 2,353	$ 26,035

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's operations are organized across two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The Liberty Power Group ("Liberty Power Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

1. Significant accounting policies

(a) Basis of preparation

The accompanying consolidated financial statements and notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosure required under Regulation S-X provided by the U.S. Securities and Exchange Commission.

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC, its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(m)). Intercompany transactions and balances have been eliminated. Interests in subsidiaries owned by third parties are included in non-controlling interests (note 1(r)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets which meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the stage of development (permitting, customer contracting, financing, construction) and the significance of the development risk with respect to achieving commercial operation. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred. When the set of activities does not represent a business, the transaction is accounted for as an asset acquisition and includes acquisitions costs.

Intangible assets acquired are recognized separately at fair value if they arise from contractual or other legal rights or are separable. Power sales contracts are amortized on a straight-line basis over the remaining term of the contract ranging from 6 to 25 years from the date of acquisition. Interconnection agreements are amortized on a straight-line basis over their estimated life of 40 years. Customer relationships are amortized on a straight-line basis over their estimated life of 40 years.

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

As at September 30 of each year, the Company assesses qualitative and quantitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge or credit against earnings for any remaining regulatory assets or liabilities. The impact could be material to the Company's reported financial condition and results of operations.

The electric, gas and water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"), the Regulator and National Association of Regulatory Utility Commissioners.

(e) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(f) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. As of December 31, 2016, restricted cash also included cash of U.S. $1,495,774 transfered to a paying agent for purposes of distribution to holders of common shares of The Empire District Electric Company and its subsidiaries ("Empire") on January 1, 2017 (note 3(a)). Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance sheet credit exposure related to its customers.

(h) Fuel and natural gas in storage

Fuel and natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents fuel, natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities and some generating facilities. Existing rate orders (note 7(d)) and other contracts allow the Company to pass through the cost of gas purchased directly to the customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the net realizable value of fuel and gas in storage does not fall below the cost to the Company.

(i) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and net realizable value. Through rate orders and the regulatory environment, capitalized construction jobs are recovered through rate base and repair and maintenance expenses are recovered through a cost of service calculation. Accordingly, the cost usually reflects the net realizable value.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management, together with the relevant authority, has authorized and committed to the funding of a project and it is probable that costs will be realized through the use of the asset or ultimate construction and operation of a facility. Project development costs for rate-regulated entities, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized either as property, plant and equipment or regulatory asset when it is determined that recovery of such costs through regulated revenue of the completed project is probable.

The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for funds used during construction (“AFUDC”) for regulated property. Where possible, individual components are recorded and depreciated separately in the books and records of the Company. Plant and equipment under capital leases are initially recorded at cost determined as the present value of minimum lease payments.

AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835, Interest. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend, equity and other income on the consolidated statements of operations.

	2017	2016
Interest capitalized on non-regulated property	**$ 5,558**	$ 3,259
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,673**	1,167
Allowance for equity funds	**3,014**	2,774
Total	**$ 10,245**	$ 7,200

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Cost incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval. Maintenance and repair costs are expensed as incurred.

Investment tax credits and government grants related to capital expenditures are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 13(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Investment tax credits and government grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method with the exception of certain wind assets, as described below. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2017	**2016**	**2017**	**2016**
Generation	**3 - 60**	3 - 60	**33**	32
Distribution	**5 - 100**	5 - 100	**40**	41
Equipment	**5 - 50**	5 - 50	**13**	11

The Company uses the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Liberty Utilities Group are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operations in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(k) Commonly owned facilities

The Company owns undivided interests in three electric generating facilities with ownership interest ranging from 7.52% to 60% with a corresponding share of capacity and generation from the facility used to serve certain of its utility customers. The Company's investment in the undivided interest is recorded as plant in service and recovered through rate base. The Company's share of operating costs are recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

As at December 31, 2017, the Company's consolidated balance sheet includes $833,578 of cost of plant in service of and $225,156 of accumulated depreciation related to commonly owned facilities. Total expenditures for the year ended December 31, 2017 were $99,930.

(l) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(m) Variable interest entities

The Company performs analysis to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8).

1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

The Company has equity and notes receivable interests in two power generating facilities. APUC has determined that both entities are considered a VIE mainly based on total equity at risk not being sufficient to permit the legal entity to finance its activities without additional subordinated financial support. The key decisions that affect the generating facilities' economic performance relate to siting, permitting, technology, construction, operations and maintenance and financing. As APUC has both the power to direct the activities of the entities that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entities that could potentially be significant to the entity, the Company is considered the primary beneficiary.

Total net book value of generating assets and long-term debt of these facilities amounts to $84,550 (2016 - $87,189) and $35,914 (2016 - $40,398), respectively. The portion of long-term debt which has recourse to the Company is $3,900 (2016 - $6,900). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $22,743 (2016 - $29,132), operating expenses and amortization of $5,564 (2016 - $6,175) and interest expense of $3,573 (2016 - $4,064).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are accounted using the equity method. Equity-method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its investees in interest, dividend, equity and other income in the consolidated statements of operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. Interest from long-term investments is recorded as earned and collectability of both the interest and principal are reasonably assured.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

(o) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, other post-employment benefit ("OPEB"), supplemental retirement program ("SERP") plans for its various employee groups in Canada and the United States. Employer contributions to the defined contribution pension plans are expensed as employees render service. The Company recognizes the funded status of its defined benefit pension plans, OPEB and SERP plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

1. Significant accounting policies (continued)

(p) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, during construction or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation and amortization expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the obligation.

(q) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expense in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(r) Non-controlling interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the equity holders of APUC. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a consolidated subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLC") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLC and partnership's agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 19).

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Class A Equity Investors would receive if an equity investment entity were to liquidate all of its assets and distribute that cash to the investors based on the contractually defined liquidation priorities. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period is the Class A Equity Investors' share of the earnings or losses from the investment for that period. Due to certain mandatory liquidation provisions of the LLC and partnership agreements, this could result in a net loss to APUC's consolidated results in periods in which the Class A Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

1. Significant accounting policies (continued)

(r) Non-controlling interests (continued)

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(s) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Qualifying renewable energy projects receive renewable energy credits ("REC") and solar renewable energy credits ("SRECs") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The REC and SREC can be traded and the owner of the REC or SREC can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at the time of generation. Any REC's or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

Revenue related to utility electricity and natural gas sales and distribution are recorded when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for certain of the Company's regulated utilities is subject to revenue decoupling mechanisms approved by their respective regulators which require to charge approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(e)).

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rates and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue is recorded net of sales taxes.

1. Significant accounting policies (continued)

(t) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period.

Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

(u) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment (note 20). Investment tax credits for our rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Other income tax credits are treated as a reduction to income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(v) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost. Long-term debt and Series C preferred shares are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities and intercompany loans are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities and intercompany loans are amortized on a straight-line basis over the term of the respective instrument.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to some of its financial instruments used to manage its foreign currency risk exposure, interest risk and price risk exposure associated with sales of generated electricity.

1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized in OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount remaining in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecasted transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

The Company's electric distribution and thermal generation facilities enter into power and gas purchase contracts for load serving and generation requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(w) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

(x) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(y) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the measurement of deferred taxes and the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This update amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718), to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of this update in the first quarter of 2017 had no material impact on the Company's consolidated financial statements. The Company continues to record the stock-based compensation expense adjusted for estimated forfeitures.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments, to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, to clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, to simplify the subsequent measurement of inventory by replacing the current lower of cost and market test with a lower of cost and net realizable value test. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years . Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update.

The FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update. The Company expects to early adopt this update on January 1, 2018.

The FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting, to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The Company applies the guidance in this update for modifications subsequent to December 15, 2017.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, to improve the reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update will also only allow the service cost component to be eligible for capitalization when applicable. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this ASU, the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

The FASB issued ASU 2017-05 Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update clarifies the scope of the standard as well as provides additional guidance on partial sales of nonfinancial assets. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted however the update must be adopted at the same time as ASU 2014-09. No impact on the consolidated financial statements is expected from the adoption of this update.

The FASB issued ASU 2017-04 Business Combinations (Topic 350): Intangibles - Goodwill and Other (Topic 350) Simplifying the Test for Goodwill Impairment. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019.

The FASB issued ASU 2017-01 Business Combinations (Topic 805): Clarifying the Definition of a Business. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The amendments in the Update should be applied prospectively. The Company will follow the pronouncements of this Update after the effective date.

The FASB issued ASU 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The Company currently present changes in restricted cash as investing activities. The adoption of this standard will change the presentation of restricted cash on the consolidated statement of cash flows.

The FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes on these transactions until the asset has been sold to an outside party. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

The FASB issued ASU 2016-15 Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this Update.

The FASB issued ASU 2016-02, Leases (Topic 842) to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The FASB issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB also voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The standard is effective for fiscal years and interim periods beginning after December 15, 2018. Early adoption is permitted.

The Company is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. The Company held training sessions with the finance team and is currently in the process of creating an inventory of its lease contracts and analyzing the terms and conditions under the requirements of this new standard. The Company continues to monitor FASB amendments to ASC Topic 842.

The FASB issued ASU 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities to simplify the measurement, presentation, and disclosure of financial instruments. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The presentation of unrealized gains/ losses from the Company's available-for-sale investments will change on the consolidated statement of comprehensive income. Certain disclosures with regards to financial liabilities will change based on the updated requirements.

The FASB issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. The core principal of the accounting guidance is that an entity should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASC 606 is expected to require significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt.

The Company has completed its impact assessment. At this point, the Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company’s information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company intends to adopt the new revenue recognition standard using the modified retrospective method.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects

(a) Acquisition of Empire

On January 1, 2017, the Company completed the acquisition of Empire, a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately U.S. $2,414,000 for the acquisition of Empire consists of cash payment to Empire shareholders of U.S. $34.00 per common share and the assumption of approximately U.S. $855,000 of debt. The cash payment was funded with the acquisition facility for an amount of U.S. $1,336,440 (note 9(b)), proceeds received from the initial instalment of convertible debentures (note 14) and existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at January 1, 2017 based on their fair values, using the exchange rate on that date of U.S. $1.00 = CAD $1.3427.

Working capital	$ 55,441
Property, plant and equipment	2,764,441
Goodwill	1,010,273
Regulatory assets	318,130
Other assets	58,553
Long-term debt	(1,218,563)
Regulatory liabilities	(195,489)
Pension and other post-employment benefits	(105,005)
Deferred income tax liability, net	(562,397)
Other liabilities	(102,759)
Total net assets acquired	$ 2,022,625
Cash and cash equivalent	$ 2,338
Total net assets acquired, net of cash and cash equivalent	$ 2,020,287

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Empire's assets is 39 years.

The table below presents the consolidated pro forma revenue and net income for the year ended December 31, 2017 and 2016, assuming the acquisition of Empire had occurred on January 1, 2016. Pro forma net income includes the impact of fair value adjustments incorporated in the preliminary purchase price allocation above and adjustments necessary to reflect the financing costs as if the acquisition had been financed on January 1, 2016. However, non-recurring acquisition-related expenses are excluded from net income.

	Year Ended December 31	
	2017	**2016**
Revenues	**$ 1,977,809**	$ 1,908,340
Net earnings attributable to common shareholders	**$ 229,976**	$ 213,983

3. Business acquisitions and development projects (continued)

(a) Acquisition of Empire (continued)

This pro forma information does not purport to represent what the actual results of operations of the Company would have been had the acquisition occurred on this date nor does it purport to predict the results of operations for future periods.

(b) Investment in joint venture with Abengoa and investment in Atlantica

On November 1, 2017, APUC entered into an agreement to create a joint venture ("AAGES") with Seville, Spain-based Abengoa, S.A ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608,000, based on a price of U.S. $24.25 per ordinary share of Atlantica plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and other closing conditions.

(c) Great Bay Solar Project

On August 12, 2015, the Company acquired rights to develop a 75 MWac solar project in Somerset County, Maryland. The project consists of four separate sites: as of December 31, 2017, two sites had been fully synchronized with the power grid, one site partially placed in service, with the remaining portion of the facility expected to be placed in service in Q1 2018.

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). Approximately U.S. $59,000 of the permanent project financing will come from tax equity investors. Equity capital contribution of U.S. $42,750 was received in 2017 with the remaining expected to be received in early 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(d) Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving customers in northern New York state. The total purchase price for the transaction is U.S. $70,000, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

(e) Approval to acquire the Perris Water Distribution System

On August 10, 2017 the Company's board approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of U.S. $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission in Q1 2018 with approval expected in late 2018.

(f) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the "Luning Holdings") is owned by the Calpeco Electric System. The 50MWac solar generating facility is located in Mineral County, Nevada. During 2016, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $7,826 as of December 31, 2016 and U.S. $31,212 on February 17, 2017. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Luning Solar project. During a six-month period in year 2022, the tax investor has the right to withdraw from Luning Holdings and require the Company to redeem its remaining interests for cash. As a result, the Company accounts for this interest as "Redeemable non-controlling interest" outside of permanent equity on the consolidated balance sheets (note 19). Redemption is not considered probable as of December 31, 2017.

On February 15, 2017, as the Luning Solar Facility achieved commercial operation, Luning Holdings obtained control for a total purchase price of U.S. $110,856.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(f) Luning Solar Facility (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	198
Property, plant and equipment		145,045
Asset retirement obligation		(714)
Non-controlling interest (tax equity)		(50,548)
Total net assets acquired	$	93,981

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

(g) Bakersfield II Solar Facility

On December 14, 2016, the Company completed construction and placed in service a 10 MWac solar powered generating facility located adjacent to the Company's 20 MWac Bakersfield I Solar Facility in Kern County, California ("Bakersfield II Solar Facility"). Commercial operations as defined by the power purchase agreement was reached on January 11, 2017.

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield II Partnership"). The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $2,454 on November 29, 2016 and approximately U.S. $9,800 on February 28, 2017. With its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(h) Wind Turbine Components Purchase

In 2016, the Company purchased approximately $75,000 of wind turbine components that will qualify between 500 MW and 700 MW of new wind powered projects for the full U.S. $0.023/kWh renewable energy production tax credit under the safe harbor guidelines established by the U.S. Internal Revenue Service, provided that such projects are placed in service before the end of 2020.

(i) Acquisition of Park Water System

On January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. The total purchase price for the Park Water System is $353,077 (U.S. $249,540), net of the debt assumed of U.S. $91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed in the consolidated statements of operations. At the time of acquisition, Park Water System owned and operated three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. Those three utilities were named Park Water Company, Apple Valley Ranchos Water Co. and Mountain Water Company.

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On June 22, 2017, the city of Missoula took possession of Mountain Water's assets (note 23(a)).

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(i) Acquisition of Park Water System (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	2,045
Property, plant and equipment		345,254
Notes receivable		1,781
Goodwill		210,463
Regulatory assets		54,548
Other assets		185
Long-term debt		(146,727)
Regulatory liabilities		(3,758)
Pension and OPEB		(18,747)
Deferred income tax liability, net		(51,795)
Other liabilities		(40,172)
Total net assets acquired	$	353,077

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions. Immaterial changes to the initial allocation were recorded during 2016.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Park Water System assets is 40 years.

The Park Water System contributed revenue of $91,817 (2016 - $96,695) and pre-tax net earnings of $17,620 (2016 - $25,374) to the Company’s consolidated financial results for the year ended December 31, 2017.

4. Accounts receivable

Accounts receivable as of December 31, 2017 include unbilled revenue of $98,214 (2016 - $57,822) from the Company’s regulated utilities. Accounts receivable as of December 31, 2017 are presented net of allowance for doubtful accounts of $6,968 (2016 - $7,064).

(in thousands of Canadian dollars, except as noted and per share amounts)

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2017

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,988,569	$ 494,912	$ 2,493,657
Distribution	5,247,499	483,345	4,764,154
Land	89,935	—	89,935
Equipment and other	143,158	51,026	92,132
Construction in progress			
Generation	263,418	—	263,418
Distribution	206,197	—	206,197
	$ 8,938,776	$ 1,029,283	$ 7,909,493

2016

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,613,267	$ 419,227	$ 2,194,040
Distribution	2,638,488	462,454	2,176,034
Land	60,868	—	60,868
Equipment and other	139,961	44,700	95,261
Construction in progress			
Generation	197,405	—	197,405
Distribution	166,338	—	166,338
	$ 5,816,327	$ 926,381	$ 4,889,946

Generation assets include cost of $142,789 (2016 - $142,246) and accumulated depreciation of $43,792 (2016 - $39,958) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,117 (2016 - $2,117).

Distribution assets include cost of $2,234,243 and accumulated depreciation of $587,202 related to regulated generation and transmission assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

For the year ended December 31, 2017, contributions received in aid of construction of $16,044 (2016 - $49,794) have been credited to the cost of the assets. The 2016 credit also includes Canadian renewable and conservation expense refundable tax credit for the St Damase wind facility in the amount of $14,086.

6. Intangible assets and goodwill

Intangible assets consist of the following:

2017

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 70,929	$ 46,263	$ 24,666
Customer relationships	33,619	11,085	22,534
Interconnection agreements	17,790	882	16,908
	$ 122,338	$ 58,230	$ 64,108

(in thousands of Canadian dollars, except as noted and per share amounts)

6. Intangible assets and goodwill (continued)

2016

		Cost		Accumulated amortization		Net book value
Power sales contracts	$	72,207	$	44,641	$	27,566
Customer relationships		35,979		10,999		24,980
Interconnection agreements		13,000		557		12,443
	$	121,186	$	56,197	$	64,989

Estimated amortization expense for intangible assets for the next year is $3,540, $3,390 in year two, $3,380 in year three, $3,040 in year four and $2,720 in year five.

All goodwill pertains to the Liberty Utilities Group. Changes in goodwill are as follows:

Balance, January 1, 2016	$	110,493
Business acquisitions		210,463
Foreign exchange		(14,315)
Balance, December 31, 2016	$	306,641
Business acquisitions (note 3(a))		1,010,273
Divestiture of operating entity (note 23(a))		(35,107)
Foreign exchange		(85,573)
Balance, December 31, 2017	$	1,196,234

7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire also provides regulated water utility distribution services to three towns in Missouri. The Empire District Gas Company, a wholly owned subsidiary, is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period. The following regulatory proceedings were recently completed:

Utility	State	Regulatory Proceeding Type	Annual Revenue Increase U.S. $'000	Effective Date
EnergyNorth Gas System	New Hampshire	GRC	$6,750	Temporary increase effective July 1, 2017
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$6,105	July 1, 2016
Calpeco Electric System	California	Post-Test Year Adjustment Mechanism	$2,175	January 1, 2018
New England Gas System	Massachusetts	GRC	$8,300	U.S. $7,800 effective March 1, 2016 U.S. $500 effective March 1, 2017
New England Gas System	Massachusetts	Gas System Enhancement Plan	$2,928	May 1, 2017
Midstates Gas System	Illinois	GRC	$2,200	June 7, 2017
Peach State Gas System	Georgia	GRAM	$2,725	March 1, 2016
Bella Vista Water System Rio Rico Water/ Sewer System	Arizona	GRC	$1,935	November 1, 2016
CalPeco Electric System	California	GRC	$8,318	January 1, 2016
Various			$3,551	2016, 2017 & 2018

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

		2017		2016
Regulatory assets				
Environmental remediation (a)	$	**103,761**	$	104,160
Pension and post-employment benefits (b)		**132,615**		75,527
Debt premium (c)		**72,016**		25,173
Fuel and commodity costs adjustment (d)		**43,311**		6,990
Rate adjustment mechanism (e)		**44,523**		40,602
Clean Energy and other customer programs (f)		**25,820**		2,106
Deferred construction costs (g)		**17,994**		—
Asset retirement (h)		**20,172**		2,113
Income taxes (i)		**45,847**		10,182
Rate case costs (j)		**11,660**		8,572
Other		**33,415**		16,539
Total regulatory assets	$	**551,134**	$	291,964
Less current regulatory assets		**(83,508)**		(48,440)
Non-current regulatory assets	$	**467,626**	$	243,524
Regulatory liabilities				
Income taxes (i)	$	**402,868**	$	1,501
Cost of removal (k)		**231,064**		110,330
Rate-base offset (l)		**16,577**		20,946
Fuel and commodity costs adjustment (d)		**29,535**		34,012
Deferred compensation received in relation to lost production (m)		**11,789**		—
Deferred construction costs - fuel related (g)		**9,306**		—
Pension and post-employment benefits (b)		**12,648**		5,481
Other		**11,269**		10,464
Total regulatory liabilities	$	**725,056**	$	182,734
Less current regulatory liabilities		**(47,278)**		(47,769)
Non-current regulatory liabilities	$	**677,778**	$	134,965

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 13(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of U.S. $21,626 relates to an acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order to be received on completion of the next general rate case. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation Non-retirement Post-employment Benefits and ASC 715 Compensation Retirement Benefits before the transfer to regulatory asset occurred. The pension and post-employments benefits liability is related to tracking accounts pertaining primarily to Park Water Company. The amounts recorded in these accounts occur when actual expenses have been less than adopted and refunds are expected to occur in future periods.

7. Regulatory matters (continued)

(c) Debt premium

Debt premium on acquired debt is recovered as a component of the weighted average cost of debt.

(d) Fuel and commodity costs adjustment

The revenue from the utilities includes a component which is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25(b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System and New England Gas Systems are subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but to be collected over a period not exceeding 24 months are accrued upon approval of the Final Order.

(f) Clean Energy and other customer programs

The regulatory asset for Clean Energy and customer programs includes initiatives related to solar rebate applications processed and resulting rebate-related costs. The amount also includes other energy efficiency programs.

(g) Deferred construction costs

Deferred construction costs reflects deferred construction costs and fuel related costs of specific generating facilities of Empire. These amounts are being recovered over the life of the plants.

(h) Asset retirement

The costs of retirement of assets are expected to be recovered through rates as well as the on-going liability accretion and asset depreciation expense.

(i) Income taxes

The income taxes regulatory assets and liabilities represent income taxes recoverable through future revenues required to fund flow-through deferred income tax liabilities and amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates.

The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $411,409.

(j) Rate case costs

The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(k) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(l) Rate-base offset

The regulators imposed a rate-base offset that will reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of 10-16 years.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

(m) Deferred compensation received in relation to lost production

The regulatory liability for deferred compensation received from lost production represents Empire's refund from Southwest Power Administration for lost revenues at one of its generating facilities. These costs are being amortized over the period approved by state regulators.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company generally earns carrying charges on the regulatory balances related to commodity cost adjustment, retroactive rate adjustments and rate case costs.

8. Long-term investments

Long-term investments consist of the following:

	2017	2016
Equity-method investees		
Red Lily I Wind Facility (a)	**$ 22,799**	$ 23,504
Deerfield Wind Project (b)	**—**	34,727
Amherst Island Wind Project (c)	**11,191**	558
Other	**6,489**	5,630
	$ 40,479	$ 64,419
Notes receivable		
Development loans (d)	**$ 37,710**	$ 32,125
Other	**4,163**	6,058
	41,873	38,183
Available-for-sale investment	**—**	169
Other investments	**2,115**	2,662
Total long-term investments	**$ 84,467**	$ 105,433

(a) Red Lily I Wind Facility

Up to April 12, 2016, the Red Lily I Partnership (the “Partnership”) was 100% owned by an independent investor. APUC provided operation and supervision services to the Red Lily I project ("Red Lily I Wind Facility"), a 26.4 MW wind energy facility located in southeastern Saskatchewan. The Company’s investment in the Red Lily I Wind Facility up to that date was in the form of subordinated debt facilities of the Partnership.

Effective April 12, 2016, the Company exercised its option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loans. The amount by which the carrying value of the Company's investment exceeds the Company's proportionate share of the Partnership's net assets is not material.

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of Red Lily I require unanimous consent. As such, APUC is deemed, under U.S. GAAP, to not have control over the Partnership. As APUC exercises significant influence over operating and financial policies of Red Lily I, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $2,776 (2016 - $1,288) to the Company's consolidated financial results for the year ended December 31, 2017.

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(b) Deerfield Wind Project

On October 19, 2015, the Company acquired a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan. On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo and obtained control of the facility.

Upon acquisition of the initial 50% equity interest of Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S. $262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S. $19,891 to the capital of Deerfield SponsorCo. Construction was completed during the first quarter of 2017 and sale of power to the utility under the power purchase agreement started on February 21, 2017. The interest capitalized during the year ended December 31, 2017 to the investment while the Deerfield Wind Project was under construction amounts to $nil (2016 - $6,072).

On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo for U.S. $21,585 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting which requires that the fair value of assets acquired and liabilities assumed in the subsidiary be recognized on the consolidated balance sheet as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of $nil was recorded on acquisition.

On May 10, 2017, tax equity funding of U.S. $166,595 was received.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working Capital	$	(14,551)
Property, plant and equipment		442,086
Construction loan		(352,666)
Asset retirement obligation		(2,816)
Deferred revenue		(1,556)
Deferred tax liability		(1,979)
Net assets acquired	$	68,518
Cash and cash equivalent	$	4,183
Net assets acquired, net of cash and cash equivalent	$	64,335

(c) Amherst Island Wind Project

Windlectric Inc. ("Windlectric") owns a 75 MW construction-stage wind development project ("Amherst Island Wind Project") in the province of Ontario. On December 20, 2016, Windlectric, a wholly owned subsidiary of the Company at the time, issued fifty percent of its common shares for $50 to a third party and as a result is no longer controlled by APUC. The Company holds an option to acquire the remaining common shares at a fixed price any time prior to January 15, 2019.

Windlectric is considered a VIE namely due to the low level of equity at risk at this point. The Company is not considered the primary beneficiary of Windlectric as the two shareholders have joint control and all decisions must be unanimous. As such, on the transaction date, the Company deconsolidated the assets and liabilities of Windlectric and recorded its retained non-controlling investment in equity and notes receivable and payable at fair value. A net gain of nil was recorded on deconsolidation. The Company is accounting for its investment in the joint venture under the equity method. The interest capitalized during the year ended December 31, 2017 to the investment while the Amherst Island Wind Project is under construction amounts to $1,447 (2016 - $491). As at December 31, 2017, the third-party construction debt of the joint venture was $133,765.

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(c) Amherst Island Wind Project (continued)

As of December 31, 2017, the Company's maximum exposure to loss of $289,374 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(d).

(d) Development loans

The Company entered into committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the equity investees' wind projects.

As at December 31, 2017, the Company has a loan and credit support facility with Windlectric of $37,710 (2016 - $29,723). The loan to Windlectric bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2019. The letters of credit are charged an annual fee of 2% on their stated amount. As of December 31, 2017, the following credit support was issued by the Company on behalf of Windlectric: $72,068 letters of credit and guarantees of obligations to the utilities under the PPAs; a guarantee of the obligations under the wind turbine, transmission line, transformer, and other supply agreements; a guarantee of the obligations under the engineering, procurement, and construction management agreements. The initial value of the guarantee obligations is recognized under other long-term liabilities and was valued at $2,449 using a probability weighted discounted cash flow (level 3).

Following acquisition of control of Deerfield SponsorCo (note 8(b)) and Odell SponsorCo LLC (note 8(e)(i)), amounts advanced to the wind project are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income from the date of acquisition.

No interest revenue is accrued on the loans due to insufficient collateral in the Joint Ventures.

(e) 2016 transactions

i. Odell Wind Facility

Up to September 15, 2016, the Company held a 50% equity interest in Odell SponsorCo LLC, which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Facility") in the state of Minnesota.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S. $26,500 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting, which requires, that the fair value of assets acquired, liabilities assumed and non-controlling interest in the subsidiary, be recognized on the consolidated balance sheets as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of nil was recorded on acquisition.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	11,836
Property, plant and equipment		469,222
Asset retirement obligation		(4,812)
Deferred tax liability		(4,273)
Non-controlling interest (tax equity investors)		(237,156)
Net assets	$	234,817

ii. Natural gas pipeline developments

During 2016, APUC wrote off an amount of $6,367 representing the total value of its equity interest in the natural gas development projects as both projects have been canceled by the developer.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity	Par value	2017	2016
Senior Unsecured Revolving Credit Facilities (a)	—	2018-2022	N/A	**$ 65,017**	$ 242,947
Senior Unsecured Bank Credit Facilities (b)	—	2018-2019	N/A	**169,343**	2,140,122
Commercial Paper (c)		2019	N/A	**6,994**	—
Canadian Dollar Borrowings					
Senior Unsecured Notes (d)	4.61%	2018-2027	$ 785,669	**781,833**	487,389
Senior Secured Project Notes	10.27%	2020-2027	$ 33,568	**33,507**	35,600
U.S. Dollar Borrowings					
Senior Unsecured Notes (e)	4.09%	2020-2047	US$1,225,000	**1,527,726**	700,600
Senior Unsecured Utility Notes (f)	5.98%	2020-2035	US$ 227,000	**309,309**	174,206
Senior Secured Utility Bonds (g)	4.95%	2018-2044	US$ 752,500	**969,567**	132,551
				$ 3,863,296	$ 3,913,415
Less: current portion				**(15,511)**	(10,075)
				$ 3,847,785	$ 3,903,340

Long-term debt issued at a subsidiary level (project notes or utility bonds) relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt issued at a subsidiary level whether or not collateralized have certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Short-term obligations of $264,214 for which the maturity has been extended beyond 12 months subsequent to the end of the year or that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

Recent financing activities:

(a) Senior unsecured revolving credit facilities

On September 20, 2017, the Company amended the terms of its $65,000 senior unsecured revolving bank credit facility to increase the commitments to $165,000 and extend the maturity from November 19, 2017 to November 19, 2018.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200,000 senior unsecured revolving credit facility ("Liberty Credit Facility") and a U.S. $200,000 revolving credit facility at Empire ("Empire Credit Facility") assumed in connection with the acquisition of Empire (note 3(a)). Subsequent to year-end on February 23, 2018, the Liberty Utilities Group' increased commitments under the Liberty Credit Facility to U.S. $500,000 and extended the maturity to February 23, 2023. Concurrent with the amendment to the Liberty Credit Facility, the Liberty Utilities Group closed the Empire Credit Facility.

On October 6, 2017, the Liberty Power Group amended the terms of its $350,000 senior unsecured revolving bank credit facility to increase the commitments to U.S. $500,000 and extended the maturity from July 31, 2019 to October 6, 2022. On October 6, 2017, the St. Damase Wind Facility entered into a $4,000 committed revolving credit facility. The facility matures on October 6, 2020 and is guaranteed by the Liberty Power Group. The facility replaces borrowings that were previously drawn under the Liberty Power Group's senior unsecured revolving credit facility. As at December 31, 2017, $3,900 had been drawn on the facility.

9. Long-term debt (continued)

(a) Senior unsecured revolving credit facilities (continued)

Liberty Power had a $150,000 bilateral revolving credit facility with a maturity date of August 19, 2018. Concurrent with the expansion of the Liberty Power Credit Facility, the Liberty Power Group closed the bilateral credit facility on October 6, 2017.

On December 31, 2017, the Liberty Power Group had an extendible one-year letter of credit facility agreement. The facility provides for issuances of letters of credit up to a maximum of $50,000 and U.S. $30,000. Subsequent to year-end, on February 16, 2018, the Liberty Power Group's increased availability under its revolving letter of credit facility to U.S. $200,000 and extended the maturity to January 31, 2021.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $4,250 of debt outstanding under its revolving credit facilities. Shortly after the closing of the acquisition, the Park Water System repaid and closed the revolving credit facilities.

(b) Senior unsecured bank credit facilities

On December 21, 2017, the Company entered into a U.S. $600,000 term credit facility with two Canadian banks maturing on December 21, 2018. On March 7, 2018 the company drew U.S. $600,000 under this facility.

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. $1,336,440 from the Acquisition Facility it obtained in 2016. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. The total amount of cash held by the paying agent of U.S. $1,495,774 is comprised of this Acquisition Facility draw of U.S. $1,336,440 and cash proceeds received from the initial instalment of convertible debentures (note 14) and is presented as restricted cash on the consolidated balance sheets. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 14) and the senior notes financing on March 24, 2017 (note 9(d)), the Company fully repaid the Acquisition Facility.

On January 4, 2016, the Company entered into a U.S. $235,000 term credit facility with two U.S. banks. On March 24, 2017, the Company repaid U.S. $100,000 of borrowings under the Corporate Term Credit Facility with proceeds from the closing of the U.S. $750,000 senior unsecured notes (notes 9(e)). In October 2017, the Company extended the maturity on its Corporate Term Credit Facility to July 5, 2019.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $22,500 of debt outstanding under a non-revolving term credit facility. In June 2017, this debt was fully repaid and closed.

(c) Commercial Paper

In connection with the acquisition of Empire (note 3(a)), the Company assumed a short-term U.S. $150,000 commercial paper program.

(d) Canadian dollar senior unsecured notes

On January 17, 2017, the Liberty Power Group issued $300,000 senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount.

In September 2017, the Company acquired an investment in an equity-investee in exchange for a note payable to the other partner of $669. Repayment of the note is expected in 2019.

(e) U.S. dollar senior unsecured notes

On March 24, 2017, the Liberty Utilities Group 's debt financing entity issued U.S. $750,000 senior unsecured notes in six tranches. The proceeds were applied to repay the Acquisition Facility (note 9(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of this financing, the Liberty Utilities Group had entered into forward contracts to lock in the underlying U.S. Treasury interest rates. Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group will be approximately 3.6%.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term debt (continued)

(f) U.S. dollar senior unsecured utility notes

On February 8, 2017, the U.S.$707 Bella Vista Water unsecured notes were fully repaid.

On January 1, 2017, in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $102,000 in unsecured utility notes. The notes consist of two tranches, with maturities in 2033 and 2035 with coupons at 6.7% and 5.8%.

(g) U.S. dollar senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $733,000 in secured utility notes. The bonds are secured by a first mortgage indenture and consist of ten tranches with maturities ranging between 2018 and 2044 with coupons ranging from 3.58% to 6.82%.

In June 2017, outstanding bonds payable for the Park Water systems in the amount of U.S. $63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 23(a). The Company had assumed the U.S. $65,000 of debt outstanding in connection with the acquisition of Park Water in 2016 (note 3(i)).

(h) U.S. dollar senior secured project notes

On March 14, 2017, in connection with the acquisition of Deerfield SponsorCo (note 8(b)), the Company assumed U.S. $262,219 in construction loan. The loans bear interest at an annual rate of 2.33% on any outstanding principal amount. On May 10, 2017, the construction loan was repaid from proceeds received from tax equity (note 8(b)) and cash contributions from APUC.

As of December 31, 2017, the Company had accrued $41,479 in interest expense (2016 - $27,225). Interest expense on the long-term debt in 2017 was $185,339 (2016 - $87,143).

Principal payments due in the next five years and thereafter are as follows:

2018	2019	2020	2021	2022	Thereafter	Total
$ 279,724	$ 179,107	$ 391,025	$ 152,626	$ 492,343	$ 2,331,327	$ 3,826,152

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to substantially all of its employees. The Company's contributions for 2017 were $9,387 (2016 - $5,223).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain existing plans. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 331,934**	$ 269,382	**$ 83,097**	$ 76,565
Projected benefit obligation assumed from business combination	**344,383**	63,811	**131,263**	9,749
Modifications to pension plan	**—**	(2,754)	**—**	(1,235)
Service cost	**17,869**	8,435	**6,280**	2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Actuarial (gain) loss	**49,785**	6,773	**13,321**	(2,870)
Contributions from retirees	**—**	—	**2,364**	547
Gain on curtailment	**(1,129)**	—	**(6)**	—
Benefits paid	**(64,605)**	(15,845)	**(8,092)**	(3,230)
Gain on foreign exchange	**(48,546)**	(10,897)	**(14,834)**	(2,870)
Projected benefit obligation, end of year	**$ 657,037**	$ 331,934	**$ 222,014**	$ 83,097
Change in plan assets				
Fair value of plan assets, beginning of year	**236,369**	176,171	**29,139**	18,149
Plan assets acquired in business combination	**247,741**	44,258	**122,900**	10,563
Actual return on plan assets	**82,096**	17,221	**25,612**	1,854
Employer contributions	**38,833**	21,776	**2,683**	2,317
Benefits paid	**(64,605)**	(15,845)	**(5,901)**	(2,683)
Loss on foreign exchange	**(33,686)**	(7,212)	**(10,737)**	(1,061)
Fair value of plan assets, end of year	**$ 506,748**	$ 236,369	**$ 163,696**	$ 29,139
Unfunded status	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)
Amounts recognized in the consolidated balance sheets consists of:				
Non-current assets	**—**	—	**4,938**	—
Current liabilities	**(1,080)**	(436)	**(1,471)**	(1,242)
Non-current liabilities	**(149,209)**	(95,129)	**(61,785)**	(52,716)
Net amount recognized	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)

The accumulated benefit obligation for the pension plans was $614,840 and $317,025 as of December 31, 2017 and 2016, respectively.

On June 22, 2017, all Mountain Water employees were terminated as a result of the condemnation of the Mountain Water assets to the city of Missoula (note 23(a)). The pension and OPEB obligations of these employees remain with the Company. The assets and projected benefit obligations of the plans were revalued at June 30, 2017 and resulted in an actuarial gain of U.S. $2,354 recorded in other comprehensive income and a curtailment gain of U.S. $853 recorded against the loss on long-lived assets.

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain of the existing plans. The plan amendments resulted in a decrease to the projected benefit obligation of U.S. $2,217 which is recorded as a prior service credit in OCI. In conjunction with the plan amendments, the assets and projected benefit obligations of amended plans were revalued at the closest month-end date which resulted in an actuarial loss of U.S. $8,204 recorded in OCI.

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2016	$ 29,461	$ (4,970)	$ (2,338)	$ —
Additions to AOCI	4,479	(2,754)	(3,242)	(1,235)
Amortization in current period	(1,965)	765	(80)	347
Balance at December 31, 2016	$ 31,975	$ (6,959)	$ (5,660)	$ (888)
Additions to AOCI	(3,716)	—	(4,276)	—
Reclassification to regulatory accounts	1,584	—	4,902	—
Amortization in current period	(1,290)	868	321	365
Balance at December 31, 2017	$ 28,553	$ (6,091)	$ (4,713)	$ (523)
Expected amortization in 2018	$ (451)	$ 781	$ 214	$ 328

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	2016	2017	2016
Discount rate	**4.01%**	4.16%	**4.12%**	4.23%
Expected return on assets	**7.01%**	6.41%	**3.88%**	5.50%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.50%
Age 65 and after			**6.25%**	6.50%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2023**	2023

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

Weighted average assumptions used to determine net benefit obligation for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Discount rate	**3.43%**	3.95%	**3.60%**	4.04%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.25%
Age 65 and after			**6.25%**	6.25%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2024**	2023

The mortality assumption for December 31, 2017 was updated to the projected generationally scale MP-2017, adjusted to reflect the ultimate improvement rates in the 2017 Social Security Administration intermediate assumptions.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2017 is as follows. The effects on total service and interest cost of a one percent change in HCCTR excludes the effects of Empire.

	2017
Effect of a 1 percentage point increase in the HCCTR on:	
Year-end benefit obligation	$ 38,047
Total service and interest cost	959
Effect of a 1 percentage point decrease in the HCCTR on:	
Year-end benefit obligation	$ (30,057)
Total service and interest cost	(765)

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(c) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Service cost	**$ 17,869**	$ 8,435	**$ 6,280**	$ 2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Expected return on plan assets	**(32,244)**	(14,854)	**(8,312)**	(1,265)
Amortization of net actuarial loss (gain)	**1,480**	1,965	**(299)**	80
Amortization of prior service credits	**(808)**	(765)	**(339)**	(347)
Gain on curtailments and settlements	**(1,394)**	—	**(6)**	—
Amortization of regulatory assets/ liability	**15,179**	4,698	**507**	1,471
Net benefit cost	**$ 27,428**	$ 12,508	**$ 6,452**	$ 6,380

(d) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	70%	49% - 79%
Debt securities	30%	21% - 51%
Other	—%	—%

The fair values of investments as of December 31, 2017, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	505,219	72%
Debt securities	164,281	27%
Other	945	—%

As of December 31, 2017, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $26,686 to its pension plans and $4,898 to its post-employment benefit plans in 2018.

The expected benefit payments over the next ten years are as follows:

	2017	2018	2019	2020	2021	2022-2026
Pension plan	$ 43,445	$ 39,037	$ 40,132	$ 45,060	$ 45,108	$ 236,821
OPEB	7,353	7,989	8,845	9,425	10,093	58,844

(in thousands of Canadian dollars, except as noted and per share amounts)

11. Mandatorily redeemable Series C preferred shares

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule indexed in proportion to the increase in CPI over the term of the shares. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

As these shares are mandatorily redeemable for cash, they are classified as liabilities in the consolidated financial statements. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:	
2018	$ 1,068
2019	1,282
2020	1,344
2021	1,364
2022	1,390
Thereafter to 2031	15,761
Redemption amount	5,340
	27,549
Less amounts representing interest	(9,085)
	18,464
Less current portion	(1,068)
	$ 17,396

12. Other assets

Other assets consist of the following:

	2017	2016
Income tax receivable	**$ 7,485**	$ 2,951
Deferred financing costs	**4,448**	10,198
Other	**18,633**	6,136
	30,566	19,285
Less current portion	**(8,919)**	(2,951)
	$ 21,647	$ 16,334

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	2017	2016
Advances in aid of construction (a)	**$ 78,636**	$ 105,191
Environmental remediation obligation (b)	**68,147**	63,378
Asset retirement obligations (c)	**55,406**	24,822
Customer deposits (d)	**35,790**	14,881
Unamortized investment tax credits (e)	**22,379**	—
Deferred credits (f)	**26,555**	44,544
Other	**55,779**	22,790
	342,692	275,606
Less current portion	**(57,586)**	(43,157)
	$ 285,106	$ 232,449

(a) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 5 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2017, $13,626 (2016 - $23,986) was transferred from advances in aid of construction to contributions in aid of construction.

(b) Environmental remediation obligation

A number of the Company's regulated utilities were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $71,873 (2016 - $76,853) which at discount rates ranging from 2.2% to 2.5% represents the recorded accrual of $68,147 as of December 31, 2017 (2016 - $63,378). Approximately $25,186 is expected to be incurred over the next two years with the balance of cash flows to be incurred over the following 28 years.

Changes in the environmental remediation obligation are as follows:

	2017	2016
Opening Balance	**$ 63,378**	$ 71,529
Remediation activities	**(2,026)**	(1,389)
Accretion	**1,447**	2,464
Changes in cash flow estimates	**2,135**	2,088
Revision in assumptions	**7,686**	(9,101)
Foreign exchange rate adjustment	**(4,473)**	(2,213)
Closing Balance	**$ 68,147**	$ 63,378

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2017, the Company has reflected a regulatory asset of $103,761 (2016 - $104,160) for the MGP and related sites (note 7(a)).

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and deferred credits (continued)

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and Polychlorinated Biphenyls "PCB" contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; (iv) remove certain river water intake structures and equipment; (v) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities. During the year, APUC assumed asset retirement obligations in connection with the acquisitions of Empire (note 3(a)) and Deerfield SponsorCo (note 8(b)) of $31,717 and $2,816, respectively, recorded additional asset retirement obligations for renewable generation facilities being constructed of $2,604 (2016 - $393), changes in estimates of $1,476 (2016 - $1,022), accretion expense of $2,551 (2016 - $1,055) and settlements of $5,418 (2016 - $nil).

As the cost of retirement of utility assets are expected to be recovered through rates, a corresponding regulatory asset is recorded, as well as the on-going liability accretion and asset depreciation expense (note 7(h)).

(d) Customer deposits

Customer deposits result from the Company's obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(e) Unamortized investment tax credits

The unamortized investment tax credits were assumed in connection with the acquisition of Empire. The investment tax credits are associated with an investment made in a generating station. The credits are being amortized over the life of the generating station.

(f) Deferred credits

Deferred credits include unresolved contingent consideration related to prior acquisitions which are expected to be paid and deferred tax credits (note 20).

14. Convertible Unsecured Subordinated Debentures

Maturity date		March 31, 2026
Interest rate		5.00%
Conversion price per share	$	10.60
Receipt of Initial instalment, net of deferred financing costs	$	357,694
Amortization of deferred financing costs		925
Carrying value at December 31, 2016		358,619
Receipt of Final instalment, net of deferred financing costs		743,881
Amortization of deferred financing costs		1,134
Conversion to common shares	$	(1,102,416)
Carrying value at December 31, 2017	$	1,218
Face value at December 31, 2017	$	1,277

On March 1, 2016, the Company completed the sale of $1,150,000 aggregate principal amount of 5.0% convertible debentures.

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount of debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the "Final Instalment") was received on February 2, 2017 ("Final Instalment Date") following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial and final instalments, net of financing costs were $357,694 and $743,881, respectively.

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Convertible Unsecured Subordinated Debentures (continued)

The convertible debentures mature on March 31, 2026 and bore interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate is 0%. The interest expense recorded for the year ended December 31, 2017 is $9,373 (2016 - $48,205). As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017.

The debentures are convertible into up to 108,490,566 common shares. As at December 31, 2017, a total of 108,370,081 common shares of the company were issued (Note 15), representing conversion into common shares of 99.9% of the convertible debentures.

After the Final Instalment Date, any debentures not converted into common shares may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

15. Shareholders' capital

(a) Common shares

Number of common shares:

	2017	2016
Common shares, beginning of year	**274,087,018**	255,869,419
Public offering (i) and subscription receipts (ii)	**43,470,000**	12,938,457
Conversion of convertible debentures (note 14)	**108,370,081**	—
Dividend reinvestment plan (iii)	**3,905,848**	2,322,618
Exercise of share-based awards (c)	**1,932,988**	2,956,524
Common shares, end of year	**431,765,935**	274,087,018

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC, subject to the rights of any shares having priority over the common shares.

The Company has a shareholders' rights plan (the "Rights Plan") which expires in 2019. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

On November 10, 2017, APUC issued 43,470,000 common shares at $13.25 per share pursuant to a public offering for proceeds of $576,000 before issuance costs of $24,342 or $17,895 net of taxes.

(ii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 from the issuance to Emera Inc. ("Emera") of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment (note 8(c)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(a) Common shares (continued)

(ii) Subscription receipts (continued)

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(i)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

(iii) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 1,063,572 common shares under the dividend reinvestment plan.

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2017 and 2016:

Preferred shares	Number of shares	Price per share	Carrying amount
Series A	**4,800,000**	**$ 25**	**$ 116,546**
Series D	**4,000,000**	**$ 25**	**97,259**
			$ 213,805

The holders of Series A and Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of $1.125 and $1.25 per share, respectively, for each year up to, but excluding December 31, 2018 and March 31, 2019, respectively. The Series A and Series D dividend rate will reset on those dates and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94% and 3.28%, respectively. The Series A and Series D preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter.

The holders of Series A and Series D preferred shares have the right to convert their shares into cumulative floating rate preferred shares, Series B and Series E, respectively, subject to certain conditions, on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter. The Series B and Series E preferred shares will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94% and 3.28%, respectively. The holders of Series B and Series E preferred shares will have the right to convert their shares back into Series A and Series D preferred shares on December 31, 2018 and March 31, 2019, respectively and every fifth year thereafter. The Series A, Series B, Series D and Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

The Company has 100 redeemable Series C preferred shares issued and outstanding. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets as they are mandatorily redeemable for cash (note 11).

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2017, APUC recorded $10,804 (2016 - $5,675) in total share-based compensation expense detailed as follows:

	2017	2016
Share options	**$ 3,990**	$ 3,006
Directors deferred share units	**771**	683
Employee share purchase	**568**	238
Performance share units	**5,475**	1,748
Total share-based compensation	**$ 10,804**	$ 5,675

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2017, total unrecognized compensation costs related to non-vested options and PSUs were $2,796 and $8,471, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 8% of the number of shares outstanding at the time the options are granted.

The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money Amount" being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

In the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board ("Compensation Committee")) in accordance with the terms of the Company's clawback policy.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was based on experience to-date. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

The following assumptions were used in determining the fair value of share options granted:

	2017	2016
Risk-free interest rate	1.4%	0.9%
Expected volatility	25%	23%
Expected dividend yield	4.3%	4.5%
Expected life	5.50 years	5.50 years
Weighted average grant date fair value per option	$ 1.45	$ 1.26

Share option activity during the years is as follows:

	Number of awards	Weighted average exercise price	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2016	7,164,652	$ 6.92	4.74	$ 28,561
Granted	2,596,025	10.85	8.00	—
Exercised	(3,715,663)	5.25	2.06	20,790
Balance at December 31, 2016	6,045,014	$ 9.64	6.27	$ 10,595
Granted	2,328,343	12.82	8.00	
Exercised	(1,634,501)	7.81	3.76	7,696
Balance at December 31, 2017	6,738,856	$ 11.18	6.32	$ 19,380
Exercisable at December 31, 2017	2,448,689	$ 10.03	5.61	$ 9,473,719

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match (a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Common shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2017, a total of 283,523 common shares (2016 - 144,264) were issued to employees under the ESPP.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2017, 293,906 (2016 - 224,663) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU Plan shall not exceed 1,000,000 common shares.

(iv) Performance share units

The Company offers a PSU plan to its employees as part of the Company's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2.0% to 237% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU Plan shall not exceed 7,000,000 common shares.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the balance sheet date. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date.

A summary of the PSUs follows:

	Number of awards	Weighted average grant-date fair value	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2016	564,116	$ 7.59	1.63	$ 6,155
Granted, including dividends	219,315	11.62	2.00	—
Exercised	(181,875)	8.29	—	2,115
Forfeited	(22,568)	9.64	—	—
Balance at December 31, 2016	578,988	$ 9.82	1.74	$ 6,595
Granted, including dividends	811,974	13.54	2.00	—
Exercised	(374,973)	8.33	—	4,394
Forfeited	(60,961)	12.61	—	—
Balance at December 31, 2017	955,028	$ 12.30	1.84	$ 13,428
Exercisable at December 31, 2017	172,031	$ 9.75	—	$ 2,423

(in thousands of Canadian dollars, except as noted and per share amounts)

16. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2016	$ 261,357	$ 39,329	$ (72)	$ (13,877)	$ 286,737
OCI (loss) before reclassifications	(61,029)	34,308	213	2,856	(23,652)
Amounts reclassified	—	(7,554)	—	(604)	(8,158)
Net current period OCI	(61,029)	26,754	213	2,252	(31,810)
Balance, December 31, 2016	$ 200,328	$ 66,083	$ 141	$ (11,625)	$ 254,927
OCI before reclassifications	(200,400)	8,714	—	838	(190,848)
Amounts reclassified	—	(6,805)	(141)	(313)	(7,259)
Net current period OCI	$(200,400)	$ 1,909	$ (141)	$ 525	$ (198,107)
Balance, December 31, 2017	$ (72)	$ 67,992	$ —	$ (11,100)	$ 56,820

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected administrative expenses.

17. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividend on its commons shares in U.S. dollars. Dividends declared in Canadian equivalent dollars during the year were as follows:

	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 242,509**	**$ 0.6084**	$ 149,158	$ 0.5452
Series A preferred shares	**$ 5,400**	**$ 1.1250**	$ 5,400	$ 1.1250
Series D preferred shares	**$ 5,000**	**$ 1.2500**	$ 5,000	$ 1.2500

18. Related party transactions

Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4,397 (2016 - U.S. $10,185). The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions amounts to U.S. $1,006 (2016 - U.S. $3,939). Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction. In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in Q2 2017 with final completion of the contract work in the fourth quarter. The total cost of the contract was $9,500. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $680 to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1,467 included in accruals in 2017 (2016 - U.S. $757) related to these transactions at the end of the year.

(in thousands of Canadian dollars, except as noted and per share amounts)

18. Related party transactions (continued)

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $5,969 (2016 - $3,313) during the year.

Trafalgar

In 2016, the Company received U.S. $10,083 in proceeds from the settlement of the Trafalgar matter, and paid U.S. $2,900 to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6,600 was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

19. Non-controlling interests and Redeemable non-controlling interest

Net loss attributable to non-controlling interests for the years ended December 31 consists of the following:

	2017	2016
HLBV and other adjustments attributable to:		
Non-controlling interest -Class A partnership units	**$ (52,020)**	$ (35,451)
Non-controlling interest -redeemable Class A partnership units	**(13,400)**	(4,952)
Other net earnings attributable to non-controlling interests	**3,172**	1,853
Net effect of non-controlling interests	**$ (62,248)**	$ (38,550)

The non-controlling Class A membership equity investors ("Class A partnership units") in the Company's U.S. wind power and solar power generating facilities are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(r).

The terms of the arrangement refer to the tax rate in effect when the benefits are delivered. As such, The U.S. federal corporate tax rate of 35% was used to calculate HLBV as at December 31, 2017. The reduced U.S. federal corporate tax rate of 21% and other certain measures discussed in note 20 will be used in the calculation of HLBV beginning in 2018.

Non-controlling interest

As of December 31, 2017, non-controlling interests of $756,007 (2016 - $562,358) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $754,932 (2016 - $561,308) and other non-controlling interests of $1,075 (2016 - $1,050). Contributions from new Class A partnership investors of U.S. $42,750 was received for the Great Bay Solar Facility in 2017 (note 3(c)); U.S. $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(g)); and, U.S. $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 8(b)).

(in thousands of Canadian dollars, except as noted and per share amounts)

19. Non-controlling interests and Redeemable non-controlling interest (continued)

Redeemable Non-controlling interest

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The redeemable non-controlling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method subsequent to initial recognition, however, if the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2017. Changes in redeemable non-controlling interest are as follows:

	2017	2016
Opening balance	**$ 29,434**	$ 25,751
Net loss attributable to redeemable non-controlling interest	**(13,400)**	(4,952)
Contributions from redeemable non-controlling interests (note 3(f))	**40,797**	10,171
Dividends declared and distributions to redeemable non-controlling interest	**(1,454)**	(590)
Foreign exchange	**(3,249)**	(946)
Closing balance	**$ 52,128**	$ 29,434

Contributions from new Class A partnership investors of U.S. $31,212 was received for the Luning Solar Facility on on February 17, 2017 (note 3(f)).

20. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2016 - 26.5%). The differences are as follows:

	2017	2016
Expected income tax expense at Canadian statutory rate	**$ 59,907**	$ 34,317
Increase (decrease) resulting from:		
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(27,671)**	(11,363)
Non-controlling interests share of income	**24,708**	13,973
Allowance for equity funds used during construction	**(1,029)**	(1,100)
Capital gain rate differential	**(919)**	(3,612)
Goodwill divestiture and permanent basis differences associated with Mountain Water condemnation	**7,059**	—
Non-deductible acquisition costs	**18,091**	1,996
Change in valuation allowance	**(1,304)**	2,841
Tax credits	**(8,162)**	(477)
Adjustment relating to prior periods	**(30)**	(711)
U.S. tax reform	**22,390**	—
Other	**2,154**	1,272
Income tax expense	**$ 95,194**	$ 37,136

On December 22, 2017, the US Tax Cuts and Jobs Act of 2017 (the Act) was signed into legislation. The Act includes a broad range of legislative changes including a reduction of the US federal corporate income tax rate from 35% to 21% effective January 1, 2018, limitations on the deductibility of interest and 100% expensing of qualified property. The Act provides an exemption to regulated utilities from the limitations on the deductibility of interest and also does not permit regulated utilities to immediately expense 100% of the cost of new investments in qualified property.

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

As a result of the Act being enacted during 2017, the Company is required to revalue its United States deferred income tax assets and liabilities based on the rates they are expected to reverse at in the future, which is generally 21% for U.S. federal tax purposes. The company was able to make reasonable estimates of the impact of the Act and has recorded provisional amounts for the remeasurement of deferred taxes. The Company has recognized a provisional charge to income tax expense of $22,390 in 2017 as a result of the revaluation of its U.S. non-regulated net deferred income tax assets. The Company has also reduced its regulated net deferred income tax liabilities by a provisional amount of $411,409 and recorded an equivalent increase to net regulatory liability since the benefit of lower U.S. taxes is probable of being returned to customers by order of the applicable regulator.

The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act.

For the years ended December 31, 2017 and 2016, earnings from continuing operations before income taxes consist of the following:

	2017	2016
Canadian operations	**$ (3,269)**	$ 29
U.S. operations	**229,309**	129,481
	$ 226,040	$ 129,510

Income tax expense (recovery) attributable to income (loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2017			
Canada	**$ 4,277**	**$ (18,390)**	**$ (14,113)**
United States	**5,631**	**103,676**	**109,307**
	$ 9,908	**$ 85,286**	**$ 95,194**
Year ended December 31, 2016			
Canada	$ 7,533	$ (10,501)	$ (2,968)
United States	928	39,176	40,104
	$ 8,461	$ 28,675	$ 37,136

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2017 and 2016 are presented below:

	2017	2016
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 412,327**	$ 459,436
Pension and OPEB	**54,744**	57,751
Acquisition-related costs	**2,008**	3,612
Environmental obligation	**18,570**	25,683
Reserves and other non-deductible costs	**38,453**	11,390
Regulatory liabilities	**193,942**	76,315
Other	**20,555**	14,374
Total deferred income tax assets	**740,599**	648,561
Less valuation allowance	**(15,486)**	(21,656)
Total deferred tax assets	**725,113**	626,905
Deferred tax liabilities:		
Property, plant and equipment	**(838,110)**	(562,124)
Intangible assets	**(8,067)**	(8,035)
Outside basis in partnership	**(157,463)**	(187,717)
Regulatory accounts	**(143,090)**	(108,506)
Financial derivatives	**(1,230)**	(17,649)
Other	**—**	(1,008)
Total deferred tax liabilities	**(1,147,960)**	(885,039)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)
Consolidated Balance Sheets Classification:		
Deferred tax assets	**$ 76,972**	$ 30,005
Deferred tax liabilities	**(499,819)**	$ (288,139)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)

The valuation allowance for deferred tax assets as at December 31, 2017 was $15,486 (2016 - $21,656). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

As of December 31, 2017, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforwards
2020 and onwards	$ 1,247,448

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of its subsidiaries. Deferred income taxes have not been provided on approximately $188,348 of undistributed earnings of certain foreign subsidiaries, as the Company has concluded that such earnings are indefinitely reinvested and should not give rise to additional tax liabilities. A determination of the amount of the unrecognized tax liability relating to the remittance of such undistributed earnings is not practicable.

(in thousands of Canadian dollars, except as noted and per share amounts)

21. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding (note 15 (a)). Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options. The convertible debentures (note 14) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

	2017	2016
Net earnings attributable to shareholders of APUC	**$ 193,094**	$ 130,924
Series A Preferred shares dividend	**5,400**	5,400
Series D Preferred shares dividend	**5,000**	5,000
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$ 182,694**	$ 120,524
Weighted average number of shares		
Basic	**382,323,434**	271,832,430
Effect of dilutive securities	**3,662,714**	2,244,602
Diluted	**385,986,148**	274,077,032

The shares potentially issuable as a result of 2,328,343 share options (2016 - 1,665,131) are excluded from this calculation as they are anti-dilutive.

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information

In connection with the acquisition of Empire on January 1, 2017, the Company aligned its management reporting under two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The two business units are the two segments of the Company.

The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these segments are reflected in the tables below. The comparative information for 2016 has been reclassified to conform with the composition of the reporting segments presented in the current year.

	Year ended December 31, 2017			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 300,173	$ 1,677,636	$ —	$ 1,977,809
Fuel, power and water purchased	25,384	485,016	—	510,400
Net revenue	274,789	1,192,620	—	1,467,409
Operating expenses	86,675	511,983	—	598,658
Administrative expenses	20,777	42,900	789	64,466
Depreciation and amortization	103,038	222,088	1,321	326,447
Gain on foreign exchange	—	—	373	373
Operating income	64,299	415,649	(2,483)	477,465
Interest expense	47,565	126,790	28,276	202,631
Interest, dividend, equity and other income	(3,723)	(5,449)	(2,817)	(11,989)
Other expenses (gain)	2,282	(4,250)	62,751	60,783
Earnings (loss) before income taxes	$ 18,175	$ 298,558	$ (90,693)	$ 226,040
Property, plant and equipment	$ 2,818,697	$ 5,047,454	$ 43,342	$ 7,909,493
Equity-method investees	37,273	2,784	422	40,479
Total assets	3,103,999	7,299,576	130,060	10,533,635
Capital expenditures	211,328	528,695	—	740,023

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

	Year ended December 31, 2016			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 265,949	$ 830,069	$ —	$ 1,096,018
Fuel and power purchased	21,260	274,055	—	295,315
Net revenue	244,689	556,014	—	800,703
Operating expenses	72,346	260,595	60	333,001
Administrative expenses	19,656	26,272	421	46,349
Depreciation and amortization	80,094	105,448	1,357	186,899
Gain on foreign exchange	—	—	(436)	(436)
Operating income	72,593	163,699	(1,402)	234,890
Interest expense	21,847	50,671	59,074	131,592
Interest, dividend and other income	32	(5,282)	(5,323)	(10,573)
Other expense (gain)	(14,403)	(11,690)	10,454	(15,639)
Earnings (loss) before income taxes	$ 65,117	$ 130,000	$ (65,607)	$ 129,510
Property, plant and equipment	$ 2,455,336	$ 2,390,047	$ 44,563	$ 4,889,946
Equity-method investees	59,021	2,314	3,084	64,419
Total assets	2,771,651	5,388,966	88,843	8,249,460
Capital expenditures	141,420	264,323	—	405,743

The majority of non-regulated energy sales are earned from contracts with large public utilities. The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations. None of the utilities contribute more than 10% of total revenue.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2017	2016
Revenue		
Canada	**$ 95,326**	$ 100,403
United States	**1,882,483**	995,615
	$ 1,977,809	$ 1,096,018
Property, plant and equipment		
Canada	**$ 568,693**	$ 558,271
United States	**7,340,800**	4,331,675
	$ 7,909,493	$ 4,889,946
Intangible assets		
Canada	**$ 34,654**	$ 36,611
United States	**29,454**	28,378
	$ 64,108	$ 64,989

Revenue is attributed to the two countries based on the location of the underlying generating and utility facilities.

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

Condemnation Expropriation Proceedings

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula could proceed with condemnation of Mountain Water's assets. The fair market value of the condemned property as of May 6, 2014 was assessed by the Commissioners to be U.S. $88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid U.S. $83,863 to Mountain Water, net of closing adjustments and amounts required to be paid by the City directly to various developers in satisfaction of obligations under Funded By Other (FBO) contracts relating to the assets.

In connection with Liberty Utilities' indirect acquisition of Mountain Water in January 2016, Liberty Utilities was permitted and continues to hold-back U.S. $14,400 from the purchase price otherwise payable to Carlyle Infrastructure Partners, L.P. ("Carlyle") and certain other interest holders.

The condemnation of the Mountain Water assets resulted in a gain on long-lived assets of U.S. $4,370.

Liberty Utilities (Apple Valley Ranchos Water) Corp. is the subject of a condemnation lawsuit filed by the town of Apple Valley. A Court will determine the necessity of the taking by Apple Valley and, if established, a jury will determine the fair market value of the assets being condemned. Resolution of the condemnation proceedings is expected to take two to three years. Any taking by government entities would legally require fair compensation to be paid, however, there is no assurance that the value received as a result of the condemnation will be sufficient to recover the Company's net book value of the utility assets taken.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2017.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases.

Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase (i)	$ 74,025	$ 48,344	$ 49,940	$ 50,214	$ 50,495	$ 254,380	$ 527,398
Gas supply and service agreements (ii)	91,425	66,848	51,809	33,161	28,411	97,489	369,143
Service agreements	47,695	47,211	48,529	48,827	46,548	435,093	673,903
Capital projects	41,054	17,064	65	65	65	16	58,329
Operating leases	9,573	8,974	8,298	8,361	9,718	225,047	269,971
Total	$263,772	$188,441	$158,641	$140,628	$135,237	$ 1,012,025	$ 1,898,744

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies (continued)

(b) Commitments (continued)

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2017. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

24. Non-cash operating items

The changes in non-cash operating items consist of the following:

	2017	2016
Accounts receivable	**$ (18,502)**	$ 6,612
Fuel and natural gas in storage	**(1,970)**	6,877
Supplies and consumable inventory	**1,392**	692
Income taxes receivable	**1,674**	145
Prepaid expenses	**(897)**	(6,161)
Accounts payable	**(23,178)**	24,524
Accrued liabilities	**25,122**	(9,454)
Current income tax liability	**(3,432)**	(4,552)
Net regulatory assets and liabilities	**(54,235)**	(14,979)
	$ (74,026)	$ 3,704

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments

(a) Fair value of financial instruments

2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 41,873	$ 47,912	$ —	$ 47,912	$ —
Derivative instruments (1):					
Energy contracts designated as a cash flow hedge	79,490	79,490	—	—	79,490
Energy contracts not designated as a cash flow hedge	137	137	—	137	—
Commodity contracts for regulated operations	92	92	—	92	—
Transmission congestion rights	7,812	7,812	—	7,812	—
Total derivative instruments	87,531	87,531	—	8,041	79,490
Total financial assets	$ 129,404	$ 135,443	$ —	$ 55,953	$ 79,490
Long-term debt	$3,863,296	$4,093,071	$ 817,895	$3,275,176	$ —
Convertible debentures	1,218	1,277	1,277	—	—
Preferred shares, Series C	18,464	18,973		18,973	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	97	97	—	—	97
Energy contracts not designated as a cash flow hedge	39	39	—	39	—
Cross-currency swap designated as a net investment hedge	72,023	72,023	—	72,023	—
Interest rate swap designated as a hedge	10,613	10,613	—	10,613	—
Currency forward contract not designated as a hedge	432	432	—	432	—
Commodity contracts for regulated operations	3,286	3,286	—	3,286	—
Total derivative instruments	86,490	86,490	—	86,393	97
Total financial liabilities	$3,969,468	$4,199,811	$ 819,172	$3,380,542	$ 97

(1) Balance of $553 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 38,183	$ 47,933	$ —	$ 47,933	$ —
Derivative instruments (1):					
Energy contracts designated as a cash flow hedge	84,554	84,554	—	—	84,554
Interest rate swap designated as a hedge	48,093	48,093	—	48,093	—
Currency forward contract not designated as a hedge	17,864	17,864	—	17,864	—
Commodity contracts for regulatory operations	359	359	—	359	—
Total derivative instruments	150,870	150,870	—	66,316	84,554
Total financial assets	$ 189,053	$ 198,803	$ —	$ 114,249	$ 84,554
Long-term debt	$3,913,415	$3,999,266	$ 517,637	$3,481,629	$ —
Convertible debentures	358,619	455,975	455,975	—	—
Preferred shares, Series C	18,460	18,613	—	18,613	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	95,404	95,404	—	95,404	—
Interest rate swaps designated as a hedge	13,385	13,385	—	13,385	—
Commodity contracts for regulated operations	36	36	—	36	—
Total derivative instruments	108,825	108,825	—	108,825	—
Total financial liabilities	$4,399,319	$4,582,679	$ 973,612	$3,609,067	$ —

(1) Balance of $314 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2017 and 2016 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace. Transmission congestion rights positions are fair valued using the most recent monthly auction clearing prices.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $22.13 to $121.56 with a weighted average of $33.20 as of December 31, 2017. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 25(b)(ii) and 25(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2017 and 2016.

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas and electric service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

		2017
Financial contracts:	Swaps	2,518,812
	Options	518,866
	Forward contracts	12,420,000
		15,457,678

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

		2017		2016
Regulatory assets:				
Swap contracts	U.S. **$**	**—**	U.S. $	—
Option contracts	U.S. **$**	**—**	U.S. $	27
Forward contracts	U.S. **$**	**6,319**	U.S. $	—
Regulatory liabilities:				
Swap contracts	U.S. **$**	**287**	U.S. $	175
Option contracts	U.S. **$**	**138**	U.S. $	92
Forward contracts	U.S. **$**	**20,909**	U.S. $	—

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
688,147	December 2023	U.S. $ 40.40	PJM Western HUB
2,926,922	December 2023	U.S. $ 29.26	NI HUB
3,330,876	December 2027	U.S. $ 36.46	ERCOT North HUB

On October 25, 2016, the Company entered into forward contracts to purchase U.S. $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500,000 bonds in relation to the acquisition of Empire (note 9(e)). The change in fair value to February 13, 2017 resulted in a gain of U.S. $36,667. The effective portion of the hedge of U.S. $718 for the year ended December 31, 2017 was recorded in OCI while the ineffective portion was recorded in the consolidated statement of operations.

The Company is party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a gain of $2,771 for the year ended December 31, 2017 (2016 - loss of $3,726), which is recorded in OCI.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

	2017	2016
Effective portion of cash flow hedge, gain	**$ 8,714**	$ 34,355
Amortization of cash flow hedge	**(30)**	(47)
Gain reclassified from AOCI	**(6,775)**	(7,554)
OCI attributable to shareholders of APUC	**$ 1,909**	$ 26,754

The Company expects $11,612 and $2,643 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company designates the amounts drawn on the Liberty Power Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency gain of $21,648 for the year ended December 31, 2017 (2016 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A gain of $23,381 (2016 - $6,156) was recorded in OCI in 2017.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 25(b)(ii)).

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 8(d)). This risk was mitigated through the use of currency forward contracts to sell U.S. $38,400 for $47,225 between July 29, 2016 and September 29, 2016. As of December 31, 2017, these instruments had settled. This currency forward contract was not accounted for as a hedge.

The Company was exposed to foreign exchange fluctuations related to the acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk was mitigated through the conversion to U.S. dollars of $359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 14) and the use of a currency forward contract to buy an amount of U.S. $567,665 for $744,050 on January 31, 2017. This currency forward contract was not accounted for as a hedge. The settlement of the currency forward contract resulted in a total realized loss of $16,412 for the year ended December 31, 2017, which is recorded as a loss on foreign exchange in the consolidated statements of operations (2016 - gain of $17,684).

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk is mitigated through the use of currency forward contracts. For the year ended December 31, 2017, a loss on foreign exchange of $432 (2016 - $nil) was recorded in the consolidated statements of operations. These currency forward contracts are not accounted for as a hedge.

For derivatives that are not designated as hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

		2017		2016
Change in unrealized loss (gain) on derivative financial instruments:				
Energy derivative contracts	$	**(52)**	$	(426)
Currency forward contract		**432**		(19,810)
Commodity contracts		**(3,916)**		—
Total change in unrealized gain on derivative financial instruments	$	**(3,536)**	$	(20,236)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps		**(193)**		—
Energy derivative contracts		**730**		951
Currency forward contract		**16,413**		(1,371)
Total realized loss (gain) on derivative financial instruments	$	**16,950**	$	(420)
Loss (gain) on derivative financial instruments not accounted for as hedges		**13,414**		(20,656)
Ineffective portion of derivative financial instruments accounted for as hedges		**805**		1,518
	$	**14,219**	$	(19,138)
Amounts recognized in the consolidated statements of operations consist of:				
Gain on derivative financial instruments		**(2,626)**		(15,849)
Loss (gain) on foreign exchange		**16,845**		(3,289)
	$	**14,219**	$	(19,138)

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Liberty Power Group accounts receivable to be significant as over 90% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S. $204,380 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2017, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2017	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 26,259	$ 38,491
Accounts receivable	14,468	238,637
Allowance for doubtful accounts	—	(5,555)
Notes receivable	37,710	3,318
	$ 78,437	$ 274,891

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2017, in addition to cash on hand of $54,550 the Company had $1,145,859 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk (continued)

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long-term debt obligations	$ 279,724	$ 570,132	$ 644,969	$2,331,327	$3,826,152
Convertible Debentures	—	—	—	1,218	1,218
Advances in aid of construction	1,502	—	—	77,134	78,636
Interest on long-term debt	172,659	307,463	250,824	1,275,184	2,006,130
Purchase obligations	501,867	—	—	—	501,867
Environmental obligation	7,765	18,858	5,373	39,877	71,873
Derivative financial instruments:					
Cross-currency swap	4,386	8,077	64,726	(5,166)	72,023
Interest rate swaps	10,613	—	—	—	10,613
Currency forward	432	—	—	—	432
Energy derivative and commodity contracts	2,290	1,035	—	97	3,422
Other obligations	44,969	—	—	110,267	155,236
Total obligations	$1,026,207	$ 905,565	$ 965,892	$3,829,938	$6,727,602

26. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

Notes

Notes

Notes

CORPORATE INFORMATION

Directors
Kenneth Moore – Chair of the Board – Managing Partner, NewPoint Capital Partners Inc.
Chris Jarratt – Vice Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
Christopher Ball – Executive Vice President, Corpfinance International Ltd.
D. Randy Laney – Former Chairman of the Board, The Empire District Electric Company
Masheed Saidi – Former Executive VP and Chief Operating Officer, U.S. Transmission, Natural Grid USA
Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy
Melissa Stapleton Barnes – Senior VP, Enterprise Risk Management, and Chief Ethics and Compliance Officer, Eli Lilly and Company
George Steeves – Principal, True North Energy

The Management Group
Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice Chair
David Bronicheski, Chief Financial Officer
Jennifer Tindale, Chief Legal Officer
Jeff Norman, Chief Development Officer
David Pasieka, Chief Operating Officer, Liberty Utilities
Mike Snow, Chief Operating Officer, Liberty Power
George Trisic, Chief Administration Officer and Corporate Secretary

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354 Davis Road
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AST Trust Company (Canada)
1 Toronto Street, Suite 1200
Toronto, Ontario, M5C 2V6

U.S. Transfer Agent
AST American Stock Transfer & Trust Company, LLC
6201 15th Avenue
Brooklyn, New York, 11219

Auditors
Ernst & Young, LLP
Toronto, Ontario

Stock Exchange
The Toronto Stock Exchange: AQN, AQN.PR.A, AQN.PR.D
The New York Stock Exchange: AQN

Legal Counsel
Blake, Cassels & Graydon LLP

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Electric Kansas Supplemental
2017 Annual Report

to the
State of Kansas

Kansas
Corporation Commission

for the year ending December 31, 2017

THE EMPIRE DISTRICT ELECTRIC COMPANY

(Exact legal name of respondent) (If name was changed during year, show previous name and date of change)

602 JOPLIN AVE PO BOX 127 JOPLIN MO 64802

(Address of principal business office at the end of the year)

Area Code 417 Telephone 625-5100 Federal ID Number 44-0236370

Gross operating revenues derived from Kansas intrastate operations	$ 24,458,979.04

GENERAL INSTRUCTIONS

1. This supplemental annual report shall be filed with the regular annual report of the respondent to the Kansas Corporation Commission, such regular report to be prepared on forms prescribed by the Federal Energy Regulatory Commission.

2. The principal purposes of this report are: (1) to set forth certain data not in the regular report or not given therein in the detail desired by this Commission, and (2) to secure data applicable to Kansas operations of the utility which will be helpful in the preparation of statistical studies and for noting trends, etc.

3. Companies operating in more than one state will be unable to assign all items relating to plant investment, operating expenses, etc. directly to separate state operations, but many items can be directly assigned. When an allocation is required, the basis therefore should be indicated (see Page 1 of this supplemental report).

4. It is not intended that companies be required to make comprehensive engineering and/or accounting studies annually in order to determine the allocations herein such as would be necessary for a general rate case. Therefore, it is desirable that for the purposes of this report, the bases of allocation be practical and reasonable so that they can be followed from year to year without substantial variation. Therefore, it is to be understood: (1) that the allocated amounts are not expected to be as accurate for any particular year as would be the case if an intensive analytical study of all facets of that year's operations had been made, (2) the acceptance of the supplementary report by the Commission does not infer approval in whole or in part of the allocation procedures followed, and (3) the utility filing the supplement is not precluded from preparing reallocations of the data submitted herein when submitting special studies in connection with rate and other matters.

5. Respondents operating wholly within the State of Kansas many, if desired, make reference to the regular report, giving page numbers, in each instance in which the data, if shown in the supplemental report, would be identical. ****Note, however, that pages 1 and 2 should be completed in their entirety.**

6. Show "None" or "Not Applicable" only when such response truly and completely states the facts. Such responses as "Not Available" and "Not Readily Available" should not be made unless their use is authorized by this Commission.

7. Sheets inserted in this report shall conform in size with the sheets herein, shall show appropriate references to tables in the main report which they support, shall have adequate margins and shall be securely bound in the report.

DO NOT FOLD OR ROLL

Subsequent Events

In the space below list all "material" events which have occurred, subsequent to the end of the reporting year and prior to the filing of this annual report, that have or will have an impact on the utility company. For each event listed describe the impact it has or will have on the utility company's financial statements and/or financial condition.

Effective February 23, 2018, our $200 million 5-year Credit Agreement, which was set to expire in October 2019, was terminated. Empire will maintain its commercial paper program but its program will be supported by a credit facility maintained by its parent company, Liberty Utilities Co. Also effective February 23, 2018, Liberty Utilities Co. entered into a new 5-year $500 million credit facility which is available to Liberty for, among other things, working capital and general corporate purposes, including supporting the working capital needs of its subsidiaries.

One Time / Unusual Occurrence

In the space below list all "material" one time or unusual occurrences, which have occurred during the reporting year for this annual report, that has or will have an impact on the utility company. For each occurrence listed describe the impact it has or will have on the utility company's financial statements and/or financial condition.

None, other than those detailed in the Notes to the Financial Statements included with this filing in the Ferc Form 1.

Corporate Guaranties

In the space below list all corporate guaranties issued by the utility or its parent on behalf of any affiliated interests as defined by K.S.A. §66-1401. for each guaranty provide the name of the affiliate along with the amount and terms including the beginning and ending dates. Describe what affect invoking the guaranty's would have on the financial condition of the utility company.

While no corporate guaranties are provided by The Empire District Electric Company, Empire's parent company, Liberty Utilities Co., provides the corporate guarantees of indebtedness listed below. Additionally, Liberty Utilities Co. provides certain performance guarantees which are listed in a separate spreadsheet being provided. Neither the debt guarantees nor the performance guarantees issued by Liberty Utilities Co. have any impact on the financial condition of The Empire District Electric Company.

Entity	Amount	Beg Date	Final Maturity	Description
Liberty Utilities GP1 – Series A	*$225 million	8/01/2012	8/01/2022	Private placement bonds (unsecured)
Liberty Utilities GP1 – Series B	$15 million	3/31/2013	3/31/2023	Private placement bonds (unsecured)
Liberty Utilities GP1 – Series C	$125 million	7/31/2013	7/31/2028	Private placement bonds (unsecured)
Liberty Utilities GP1 – Series D	$160 million	4/30/2015	7/15/2045	Private placement bonds (unsecured)
Liberty Utilities GP1 – Series E	$750 million	3/24/2017	4/30/2047	Private placement bonds (unsecured)
Liberty Utilities America (Holdco)	**$135 million	1/04/2017	7/05/2019	Term Loan

* Only $175 million of the Liberty Utilities GP1 Series A private placement bonds remain outstanding.
** Originally $235 million.

Cross Default Clauses

In the space below list all of the affiliates' (as defined by K.S.A. §66-1401) debt obligations that contain cross-default clauses linking the affiliates' performance under the debt agreements to the utility and/or its parent. For each debt obligation with a cross-default clause provide the name of the affiliate, a concise description of its business and a description of the debt obligation. Describe what effect invoking the cross default clause(s) would have on the financial condition of the utility company.

Empire does not have any cross default clauses in its agreements. However, its parent company, Liberty Utilities Co., has a cross default provision in its bank credit facility which becomes effective once $40 million of indebtedness is in default. Regardless, the Liberty Utilities Co. cross default clause has no impact on the financial condition of The Empire District Electric Company.

BASES OF ALLOCATION TO KANSAS OF UTILITY PLANT, OPERATING EXPENSES, ETC.

1. In column (a), assign allocation basis reference numbers for each basis used in allocating Utility Plant and other items applicable to Kansas operations.
2. In column (b), give a full description of each basis of allocation, showing designations and amounts of the factors involved in each equation or formula.
3. In column (c), for each basis, show the percent of the Kansas portion to the total.

Line No.	Reference Number (a)	Full Description of Basis of Allocation (b)			Percent to Kansas* (c)
		Description	Total Company	Kansas	
1	63	Peak Demand - Kw	891,000	44,917	5.0412%
		Electric Plant in Service			
2	24	Production	$ 1,330,167,814	$ 67,191,615	5.0514%
3	24	Transmission	359,691,942	18,132,619	5.0412%
4		Distribution	949,080,504	52,530,043	5.5348%
5		Subtotal	2,638,940,260	137,854,277	5.2238%
6	4	General	88,182,128	4,606,502	5.2238%
7	4, 64	Intangible	41,369,395	2,161,075	5.2238%
8		Total	$ 2,768,491,783	$ 144,621,854	5.2238%
		Construction Work in Progress			
9	1	Production	$ 8,388,022	$ 423,709	5.0514%
10	2	Transmission	12,036,190	606,763	5.0412%
11	63	Distribution	9,746,078	691,632	7.0965%
12	5	General	1,593,623	83,249	5.2239%
13		Total	$ 31,763,913	$ 1,805,353	5.6837%
14	63	Distribution Plant	$ 949,080,504	$ 52,530,043	5.5348%
15	63	Less: Nondepreciable	4,128,843	86,323	2.0907%
		Depreciable			
16	63	Distribution Plant	$ 944,951,661	$ 52,443,720	5.5499%
		Reserve for Depreciation:			
17	1	Production **	$ 288,396,254	$ 14,506,332	5.0300%
18	2	Transmission	94,678,045	$ 4,772,910	5.0412%
19	25	Distribution	419,838,561	$ 23,300,620	5.5499%
20	5	General	48,929,875	$ 2,556,048	5.2239%
21	4	Amort Of Electric Plant	18,929,632	$ 988,856	5.2239%
22		Total	$ 870,772,366	$ 46,124,765	5.2970%

*Cents may be used to accomplish correct rounding of percentages shown in column c
**This does not include $37,312,953 in MO Regulatory Plan Amortization.

BASES OF ALLOCATION TO KANSAS OF UTILITY PLANT, OPERATING EXPENSES, ETC.

1. In column (a), assign allocation basis reference numbers for each basis used in allocating Utility Plant and other items applicable to Kansas operations.
2. In column (b), give a full description of each basis of allocation, showing designations and amounts of the factors involved in each equation or formula.
3. In column (c), for each basis, show the percent of the Kansas portion to the total.

Line No.	Reference Number (a)	Full Description of Basis of Allocation (b)			Percent to Kansas (c)
		Description	Total Company	Kansas	
		Depreciation Expense:			
23	1	Production	$ 35,044,516	$ 1,635,525	4.6670%
24	2	Transmission	7,463,322	374,343	5.0158%
25	25	Distribution	30,144,308	1,665,655	5.5256%
26	5	General	2,979,152	155,627	5.2239%
27	4	Amort Of Electric Plant	3,462,768	180,890	5.2239%
28		Total *	$ 79,094,066	$ 4,012,040	5.0725%
29	63	On-System Kwh Sales	4,841,356,195	229,047,531	4.7311%
30	63	Average Customers	171,839	9,668	5.6262%
		Revenues:			
31	Actual	On-System	$ 549,050,613	$ 24,458,979	4.4548%
32	38	Off-System Wholesale	33,325,432	$ 1,698,563	5.0969%
33	3	Trans Peaking Service	335,289	-	0.0000%
34		Total	$ 582,711,334	$ 26,157,542	4.4889%
		Production Expenses:			
		On-System:			
35	23	Variable	$ 134,675,530	$ 6,745,441	5.0087%
36	24	Fixed	43,937,242	2,368,581	5.3908%
37		Subtotal	178,612,772	9,114,022	5.1027%
38	23, 24	Off-System:	-	-	#DIV/0!
39		Total Production	$ 178,612,772	$ 9,114,022	5.1027%
40	2	Transmission Expenses	$ 25,025,575	$ 1,270,811	5.0780%
41	3	Distribution Expenses	$ 24,890,648	$ 1,352,257	5.4328%
42	61	Customer Accounts	$ 8,353,756	$ 470,016	5.6264%
43	61, 63	Customer Assistance	$ 4,035,808	$ 105,754	2.6204%
44	35	Sales Expenses	$ 158,081	$ 7,084	4.4812%
		Subtotal of Above			
45		On-System Expenses	$ 241,076,640	$ 12,319,944	5.1104%

* This does not include $37,312,953 in MO Regulatory Plan Amortization.

BASES OF ALLOCATION TO KANSAS OF UTILITY PLANT, OPERATING EXPENSES, ETC.

1. In column (a), assign allocation basis reference numbers for each basis used in allocating Utility Plant and other items applicable to Kansas operations.
2. In column (b), give a full description of each basis of allocation, showing designations and amounts of the factors involved in each equation or formula.
3. In column (c), for each basis, show the percent of the Kansas portion to the total.

Line No	Reference Number (a)	Full Description of Basis of Allocation (b)			Percent to Kansas (c)
		Description	Total Company	Kansas	
		Administrative and General:			
46	44	EPRI Research	$ -	$ -	#DIV/0!
47	63	Franchise Requirements	-	-	#DIV/0!
48	63	Regulatory Commission	1,340,377	61,449	4.5845%
49	Lbr	Other	51,822,746	2,942,653	5.6783%
50		Total	$ 53,163,123	$ 3,004,102	5.6507%
		Taxes Other Than Income Taxes			
51	7	Property	$ 22,644,309	$ 1,182,905	5.2239%
52	Lbr	Payroll	3,781,806	214,494	5.6717%
53		Environment	-	-	#DIV/0!
54	63	Other	9,840,564	445,459	4.5268%
55		Total	$ 36,266,679	$ 1,842,858	5.0814%
		Income Taxes:			
		Current (Account 409.1)			
56	65	Federal	$ 2,154,611	$ 46,123	2.1407%
57	65	State	$ 2,863,190	$ 61,291	2.1407%
58		Deferred (Account 410.1)	$ 76,337,108	$ 877,413	1.1494%
59		Deferred in Prior Years (Account 411.1)	$ 3,219,563	$ 956,487	29.7086%
60		Investment Tax Credit - Net (Account 411.4)	$ (141,239)	$ (1,642)	1.1626%
61		Total Income Taxes	$ 84,433,233	$ 1,939,672	2.2973%

ELECTRIC PLANT IN SERVICE – KANSAS ONLY

(In addition to Account 101, Electric Plant in Service (Classified), this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Electric Plant in Process of Reclassification, and Account 106, Completed Construction not Classified – Electric.

1. Report to the nearest dollar (cents omitted) the original cost of electric plant in service according to prescribed accounts.
2. This table is the equivalent of two tables in one: First – Columns (b) to (e), inclusive, call for all Electric Plant in Service which is physically located in Kansas, regardless of how much is applicable to various states: - Columns (f) to (h), inclusive, are concerned with determining the amounts of Electric Plant in Service applicable to Kansas operations at the end of the year, regardless of location.
3. In Column (f), show amounts at the end of the year representing plant which applies wholly to Kansas operations, irrespective of the physical location of such plant.
4. In Column (g), show the allocated Kansas portion of plant in service at the end of the year which is common to operations of Kansas and one or more other states, irrespective of the physical location of such plant.
5. Although no Column is provided for it, the total Electric Plant in Service applicable to Kansas operations is the total of amounts in Columns (f) and (g).
6. Column (h) shall show the reference numbers to allocation bases used in computing amounts in column (g). Allocations shall be based on generally accepted engineering and accounting principles (See table "Bases of Allocation to Kansas of Electric Plant in Service and Electric Operating Expenses", page 1).
7. If the same basis of allocation is applied to several accounts within a group (e.g. Accounts 330 to 336, inclusive), the total amount allocated to Kansas for such accounts may be shown if desired, in column (g) in a blank line at the bottom of the group and reference numbers shown in Column (h) instead of individual amounts for each account to the group so included.
8. Column (i) shall show the amounts of Electric Plant in Service at the end of the year which is common to Kansas and one or more other states. To determine such common plant: From the entire company total of the account or group of accounts, subtract (1) amounts directly assignable to Kansas, (2) amounts directly assignable to other states and (3) any other amounts located in other states, no part of which is applicable to Kansas.
9. If adjustments are included in column (c) and/or column (d), set forth by footnote (See page 5) the amount of debits and credits together with explanation.
10. State in a footnote or an insert on what dates journal entries for the year with respect to Accounts 102, "Electric Plant Purchased or Sold" was submitted to this Commission for approval.

ELECTRIC PLANT IN SERVICE - KANSAS ONLY (See Instructions on previous page)

			LOCATED IN KANSAS				BALANCE AT END OF YEAR			
							Applicable to Kansas Operations			
Line No	Account No	Account (a)	Balance Beginning Of Year (b)	Additions (c)	Retirements (d)	Balance End Of Year (e)	Assigned Direct (f)	Allocated Amount (g)	Allocated Ref. No. (h)	Common to Kansas & Other States (i)
		1. INTANGIBLE PLANT								
1	301	Organization	$ 29,940			$ 29,940				$ 29,940
2	302	Franchises and Consents	-			-				1,079,798
3	303	Miscellaneous Intangible Plant	-	14,537		14,537				40,259,657
4		Total Intangible Plant	29,940	14,537	-	44,477	-	2,161,075	7	41,369,395
		2. PRODUCTION PLANT								
		Steam Production Plant								
5	310	Land and Land Rights	125,248			125,248				2,435,380
6	311	Structures and Improvements	4,888,816	(103,132)	2,621,571	2,164,113				82,531,040
7	312	Boiler Plant Equipment	65,560		1,350	64,210				535,460,400
8	313	Eng's and Eng Driven Generator				-				-
9	314	Turbo-generated Units				-				117,802,563
10	315	Accessory Electric Equipment	409,165		398,249	10,916				37,987,628
11	316	Misc Power Plant Equipment				-				7,785,674
	317	Asset Retirement Costs								17,721,371
12		Total Steam Production Plant	5,488,789	(103,132)	3,021,170	2,364,488		40,497,998	2	801,724,056
		Nuclear Production Plant								
13	320	Land and Land Rights				-				
14	321	Structures and Improvements				-				
15	322	Reactor Plant Equipment				-				
16	323	Turbo-generator Units				-				
17	324	Accessory Electric Equipment				-				
18	325	Misc Power Plant Equipment				-				
		Total Nuclear Production Plant				-				
		Hydraulic Production Plant								
20	330	Land and Land Rights				-				226,488
21	331	Structures and Improvements				-				810,803
22	332	Reservoirs, Dams, & Waterways				-				3,417,693
23	333	Water Whls, Turb, & Generators				-				3,161,774
24	334	Accessory Electric Equipment				-				1,449,464
25	335	Misc Power Plant Equipment				-				597,207
26	336	Roads, Railroads, & Bridges				-				-
27		Total Hydraulic Production Plant	-	-	-	-		488,135		9,663,429

ELECTRIC PLANT IN SERVICE - KANSAS ONLY (See Instructions on previous page)										
			LOCATED IN KANSAS				BALANCE AT END OF YEAR			
							Applicable to Kansas Operations			
								Allocated		
Line No	Account No	Account (a)	Balance Beginning Of Year (b)	Additions (c)	Retirements (d)	Balance End Of Year (e)	Assigned Direct (f)	Amount (g)	Ref No (h)	Common to Kansas & Other States (i)
		Other Production Plant								
28	340	Land and Land Rights	253,184			253,184				1,267,014
29	341	Structures and Improvements	25,336,964	369,899	(138,727)	25,845,590				41,289,140
30	342	Fuel Holders, Prod, & Access	1,402,589	76,741		1,479,330				7,857,146
31	343	Prime Movers	158,121,890	336,925	188,056	158,270,759				366,185,124
32	344	Generators	22,975,819	156,994		23,132,813				64,542,447
33	345	Accessory Electric Equipment	28,116,266	77,342		28,193,608				45,026,684
34	346	Misc Power Plant Equipment	3,443,784	136,846		3,580,631				10,334,144
35		Total Other Prod Plant	239,650,496	1,154,748	49,329	240,755,915	-	27,100,652	2	536,501,699
36		Total Production Plant	245,139,285	1,051,616	3,070,498	243,120,403	-	67,191,615		1,347,889,184
		3. TRANSMISSION PLANT								
37	350	Land and Land Rights	143,082	300		143,382				11,923,369
38	351	Clearing Land and Rights of Way				-				-
39	352	Structures and Improvements	84,718	(377)	5,294	79,048				2,906,760
40	353	Station Equipment	20,129,069	1,032,825	88,849	21,073,044				162,246,746
41	354	Towers and Fixtures	1,135,310	37,206		1,172,516				1,817,801
42	355	Poles and Fixtures	9,768,216	(502,126)	6,798	9,259,292				90,738,372
43	356	Overhead Conductors & Devices	11,199,200	511,335	1,129	11,709,407				90,058,893
44	357	Underground Conduit				-				
45	358	Underground Conductors & Devices				-				
46	359	Roads and Trails				-				
47		Total Transmission Plant	42,459,596	1,079,163	102,070	43,436,689	-	18,132,619	3	359,691,941
		4. DISTRIBUTION PLANT								
48	360	Land and Land Rights	120,470	(34,147)		86,324	86,324			4,128,842
49	361	Structures and Improvements	639,468			639,468	639,468			26,143,006
50	362	Station Equipment	4,427,471	431,281		4,858,752	4,858,752			124,780,101
51	363	Storage Battery Equipment	-			-	-			-
52	364	Poles, Towers & Fixtures	17,258,817	1,261,474	60,133	18,460,158	18,460,158			208,028,481
53	365	Overhead Conductors & Devices	12,280,500	1,276,602	68,352	13,488,751	13,488,751			210,763,682
54	366	Underground Conduit	506,317	87,801	3,367	590,752	590,752			43,013,009
55	367	Underground Conductors & Devices	705,022	29,852	2,666	732,209	732,209			65,807,158
56	368	Line Transformers	5,048,948	334,833	101,824	5,281,957	5,281,957			120,421,884
57	369	Services	4,354,828	152,683	1,653	4,505,859	4,505,859			84,450,221
58	370	Meters	1,313,545	548,265	493,744	1,368,065	1,368,065			24,570,957
59	371	Installations on Cust Premises	1,547,705	27,790	28,482	1,547,013	1,547,013			17,104,340

ELECTRIC PLANT IN SERVICE - KANSAS ONLY (See Instructions on previous page)										
			LOCATED IN KANSAS				BALANCE AT END OF YEAR			
							Applicable to Kansas Operations			
Line No.	Account No.	Account (a)	Balance Beginning Of Year (b)	Additions (c)	Retirements (d)	Balance End Of Year (e)	Assigned Direct (f)	Allocated Amount (g)	Allocated Ref No (h)	Common to Kansas & Other States (i)
60	372	Leased Property on Cust Premises				-	-			-
61	373	Street Light & Signal Systems	981,130	18,475	28,867	970,738	970,738			19,717,510
61	374	Asset Retirement Costs				-	-			183,153
62		Total Distribution Plant	49,184,221	4,134,909	789,087	52,530,043	52,530,043	-	-	949,112,344
		5. General Plant								
63	389	Land and Land Rights	21,537			21,537				1,057,907
64	390	Structures and Improvements	200,361			200,361				11,697,714
65	391	Office Furniture & Equipment	273,404	26,591	3,493	296,502				20,862,734
66	392	Transportation Equipment	1,135,810	2,850	(33,589)	1,172,249				14,341,659
67	393	Stores Equipment	3,497	1,012		4,509				855,334
68	394	Tools, Shop, & Garage Equip	403,414	8,137		411,551				6,974,820
69	395	Laboratory Equipment	3,218	2,217		5,435				1,985,646
70	396	Power Operated Equipment	1,927,005	2,850	140,690	1,789,164				18,252,136
71	397	Communication Equipment	266,507	927	1,138	266,296				11,876,741
72	398	Miscellaneous Equipment	7,420			7,420				277,438
82		Subtotal	4,242,174	44,583	111,732	4,175,025	-	-	-	88,182,129
83	399	Other Tangible Property*				-				
84		Total (Accounts 101 and 106)	341,055,217	6,324,809	4,073,387	343,306,638	52,530,043	87,485,309		2,786,244,993
85	102	Electric plant purchased**				-				
86	102	Electric plant sold***				-				
87	103	Electric plant in process of reclass				-				
88		Total Electric Plant in Service	341,055,217	6,324,809	4,073,387	343,306,638	52,530,043	87,485,309	-	2,786,244,993

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing sub-account classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing

*** If any property is reported as "in process of reclassification," submit a supporting schedule showing amount of such property according to detail accounts in which classified.

Footnotes:

1. This table should be submitted with amounts to the nearest dollar (cents omitted).
2. Amounts shown hereunder shall be as of the year end. Show in column (e) reference to allocation bases set forth on page 1 of the Supplemental Report.

Item (a)	Applicable to Kansas: Total Company (b)	Applicable to Kansas: Assigned Direct (c)	Applicable to Kansas: Allocated: Amount (d)	Applicable to Kansas: Allocated: Ref No (e)	Common to Kansas and Other States (f)
ELECTRIC PLANT					
Electric plant in service (101, 102, 103, and 106: from pg 5, line 88	2,786,244,993	52,530,043	144,621,854	(7)	2,786,244,993
Electric plant leased to others (104)					
Electric plant held for future use (105)	872,756	-	43,997	(8)	872,756
Construction work in prog-electric (107)	31,763,912	(691,632)	1,113,720	(15)	31,763,912
Electric plant acquisition adj (114)					
Other Electric Plant Adjustments (116)					
Total electric utility plant (Lines 1-6, inclusive)	2,818,881,661	51,838,411	145,779,571		2,818,881,661
ACCUM PROVISION FOR DEPR & AMORT OF ELECTRIC PLANT					
Accum provisions for depreciation of electric plant in service (108)-by functional divisions:					
(a) Steam production	157,448,913		7,919,680		157,448,913
(b) Nuclear production					
(c) Hydraulic production	3,128,374		157,357		3,128,374
(d) Other production	127,818,967		6,429,294		127,818,967
(e) Transmission	94,678,045		4,772,910		94,678,045
(f) Distribution	419,838,561		23,300,620		419,838,561
(g) General	48,929,875		2,556,048		48,929,875
(h) TOTAL FUNCTIONAL DIVISIONS OF (ACCOUNT 108)	851,842,734	-	45,135,909		851,842,734
Accumulated provisions for amort of electric plant in service (111)	18,929,632		988,856	(12)	18,929,632
TOTAL ACCUMULATED PROVISIONS FOR DEPRECIATION & AMORTIZATION FOR ELECTRIC PLANT IN SERVICE (Lines 8&9)	870,772,366	-	46,124,765		870,772,366
Accumulated provision for depr of electric plant leased to others (109)					
Accumulated provision for depr of electric plant leased to others (110)					
Accumulated provision for amort of electric plant leased to others (112)					
Accumulated provision for amort of electric plant leased to others (113)					
Accumulated provision for amort of electric plant acquisition adj (115)					
TOTAL ACCUMULATED PROVISIONS FOR DEPRECIATION & AMORTIZATION OF ELECTRIC PLANT (Lines 10-15, inclusive)	870,772,366	-	46,124,765		870,772,366

ELECTRIC OPERATING INCOME

Line No	Account (a)	Total Company Current Year (b)	Total Company Increase (c)	Kansas Operations Current Year (d)	Kansas Operations Increase (e)	All Other Operations Current Year (f)	All Other Operations Increase (g)
1	UTILITY OPERATING INCOME						
2	Operating Revenues (400)	582,711,334	16,009,826	24,458,979	415,993	558,252,355	15,593,833
3	Operating Expenses:						
4	Operation Expenses (401)	247,918,769	(12,673,665)	12,904,075	(1,949,694)	235,014,694	(10,723,971)
5	Maintenance Expenses (402)	46,433,155	1,321,874	2,425,694	(145,649)	44,007,461	1,467,523
6	Depreciation Expense (403)	75,631,298	(994,468)	3,831,150	(70,851)	71,800,148	(923,617)
7	Amort & Depl of Utility Plant (404-405)	3,462,768	412,834	180,890	20,349	3,281,878	392,485
8	Amort of Utility Plant Acq Adj (406)						
9	Amort of Property Losses (407)						
10	Amort of Conversion Expense (407.2)						
11	Plant Disallowance (426.5)	-	-		-	-	-
12	Taxes Other Than Income Taxes (408.1)	36,266,679	1,476,232	1,842,858	78,542	34,423,821	1,397,690
13	Income Taxes - Federal (409.1)	2,154,611	1,415,564	46,123	25,796	2,108,488	1,389,768
14	Income Taxes - Other (409.1)	2,863,190	2,863,190	61,291	61,291	2,801,899	2,801,899
15	Provision for Deferred Inc Taxes (410.1)	76,337,108	10,990,989	877,413	(611,798)	75,459,695	11,602,787
16	Income Taxes Def in Prior Yrs-Cr (411.1)	3,219,563	27,921,368	956,487	1,418,825	2,263,076	26,502,543
17	Investment Tax Credit Adj - Net (411.4)	(141,239)	(197)	(1,642)	1,607	(139,597)	(1,804)
18	Gains from Disp of Utility Plant (411.6)	(11)	(11)	-	-	(11)	(11)
19	Losses from Disp of Utility Plant (411.7)						
20	Total Utility Operating Expense	494,145,891	32,733,710	23,124,339	(1,171,582)	471,021,552	33,905,292
21	Net Utility Operating Income	88,565,443	(16,723,884)	1,334,640	1,587,575	87,230,803	(18,311,459)
22	(carry forward to page 117, line 21)						

Footnotes:

Depreciation Expense (403) on Line 6 does not include $0 in Missouri Regulatory Plan Amortization

Accounts 410.1 and 411.1 will not tie directly to Kansas Pg 3B due to taxes recorded "below the operating line."

Operating Revenues above on line 2, column b include $33.3 million in regional transmission (SPP) sales for resale. None of this has been allocated to Kansas.

ELECTRIC OPERATING REVENUES (Account 400) KANSAS ONLY

1. Report below the amount of operating revenue for the year for each prescribed account and the amount of increase or decrease over the preceding year.
2. If increases and decreases are not derived from preciously reported figures, explain any inconsistencies.
3. Number of customers should be reported on the basis of number of meters, plus number of flat rate accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added. The average number of customers means the average of the 12 figures at the close of each month If the customer count in the residential service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.
4. Unmetered sales should be included below. The details of such sales should be given in a footnote.
5. Classification of Commercial and Industrial Sales, Account 442, according to Small (or Commercial) and Large (or Industrial) may be according to the basis of classification regularly used by the respondent if such basis of classification is not greater generally than 1000 KS of demand. See Account 442 of the Uniform System of Accounts. Explain basis of classification.

			OPERATING REVENUES			KILOWATT-HOURS SOLD			AVG NUMBER OF CUSTOMER/MONTH		
Line No	Account No	Account	Amount for Year	Inc or Dec from Prev Yr		Amount for Year	Inc or Dec from Prev Yr		Amount for Year	Inc or Dec from Prev Yr	
1		SALES OF ELECTRICITY									
2	440	Residential Sales	11,348,838	(23,137)		101,323,138	(4,174,765)		8,196	(10)	
3	442	Commercial & Industrial Sales									
4		Small (Commercial) see Inst 5	5,936,910	130,799		50,717,706	(888,122)		1,261	28	
5		Large (Industrial) see Inst 5	5,101,815	322,743		61,610,556	1,787,418		50	1	
6	444	Public Street and Highway Light	257,446	2,940		1,767,416	(27,106)		54	(1)	
7	445	Other Sales to Public Authorities	468,065	(22,207)		3,878,960	(313,648)		102	(9)	
8	446	Sales to Railroads & Railways									
9	448	Interdepartmental Sales	25,805	(6,914)		122,455	(76,653)		4	-	
10		TOTAL SALES OF ULTIMATE CONSUMERS	23,138,879	404,224		219,420,231	(3,692,876)		9,667	9	
11	447	Sales for Resale	722,929	37,821		9,627,300	(690,720)		1	-	
12		TOTAL SALES OF ELECTRICITY	23,861,808	442,045		**229,047,531**	**(4,383,596)**		**9,668**	**9**	
13		OTHER OPERATING REVENUES									
14	450	Forfeited Discounts	117,029	(4,674)							
15	451	Miscellaneous Service Revenue	4,925	(505)							
16	453	Sales of Water and Water Power									
17	454	Rent from Electric Property	33,620	(10,778)							
18	455	Interdepartmental Rents									
19	456	Other Electric Revenues	441,597	(10,095)							
20		TOTAL OTHER OPERATING REVENUES	597,171	(26,052)							
21											
22		TOTAL ELECTRIC OPERATING REVENUES	**24,458,979**	**415,993**							
23											
24											
25											

(See page 108 Important Changes During the Year, for important new territory added important rate increase or decrease)

SALES OF ELECTRICITY BY RATE SCHEDULES - KANSAS OPERATIONS ONLY

1. Report below for each Kansas rate schedule in effect during the year the data as called for in the several columns unless such data will be duplication of information shown on page 304 of the regular report (in which case, merely make reference below to page 304 or the regular report).
2. Provide a subheading and total for each operating revenue account in the sequence followed on page 8 of this supplement. If the sales under any rate schedule are classified in more than one revenue account list the rate schedule and sales data under each applicable revenue account subheading.
3. Instructions 3, 4, and 5 of the schedule on page 304 of the regular report to be followed are also to be followed in preparation of the information below.

Line No	Number & Title of Rate Schedule (a)	Kwh Sold (b)	Revenue (c)	Avg No Customers (d)	Kwh Sales per Cust (e)	Revenue per Kwh Sold (f)
1	**Residential:**					
2	PL Private Lighting	650,845	222,969	17	38,285	0.3426
3	RG Residential Service	59,681,601	6,925,745	5,547	10,759	0.1160
4	RG Residential w/Water Heating	10,296,179	1,118,188	766	13,441	0.1086
5	RH Residential Total Electric	31,127,159	3,108,274	1,866	16,681	0.0999
6	SH Small Heating	0	0	0	0	
7	Sub-Total	101,755,784	11,375,176	8,196	12,415	0.1118
8						
9	Unbilled Revenue	-432,646	-26,338			
10						
11	Total	101,323,138	11,348,838	8,196	12,363	0.1120
12						
13	**Commercial:**					
14	CB Commercial	16,449,360	2,213,349	1,038	15,847	0.1346
15	SH Small Heating	2,220,599	260,937	100	22,206	0.1175
16	PL Private Lighting	650,021	185,077	15	43,335	0.2847
17	TEB Total Electric Building	7,809,532	795,864	35	223,129	0.1019
18	GP General Power	23,568,186	2,468,423	64	368,253	0.1047
19	LS Special Lighting	56,008	9,059	9	6,223	0.1617
20	RG Residential Service	0	0	0	0	#DIV/0!
21	Sub-Total	50,753,706	5,932,709	1,261	40,249	0.1169
22						
23	Unbilled Revenue	-36,000	4,201			
24						
25	Total	50,717,706	5,936,910	1,261	40,220	0.1171
26						
27	**Industrial:**					
28	CB Commercial	279,234	34,620	9	31,026	0.1240
29	SH Small Heating	246,367	27,038	7	35,195	0.1097
30	TEB Total Electric Building	879,680	87,083	3	293,227	0.0990
31	PL Private Lighting	153,913	38,547	0	0	0.2504
32	GP General Power	12,359,682	1,334,304	26	475,372	0.1080
33	PT Transmission Service	47,713,237	3,579,799	5	9,542,647	0.0750
34	Sub-Total	61,632,113	5,101,391	50	1,232,642	0.0828
35						
36	Unbilled Revenue	-21,557	424			
37						
38	Total	61,610,556	5,101,815	50	1,232,211	0.0828
39						
40						
41						
42						

SALES OF ELECTRICITY BY RATE SCHEDULES - KANSAS OPERATIONS ONLY

1. Report below for each Kansas rate schedule in effect during the year the data as called for in the several columns unless such data will be duplication of information shown on page 304 of the regular report (in which case, merely make reference below to page 304 or the regular report).
2. Provide a subheading and total for each operating revenue account in the sequence followed on page 8 of this supplement. If the sales under any rate schedule are classified in more than one revenue account list the rate schedule and sales data under each applicable revenue account subheading.
3. Instructions 3, 4, and 5 of the schedule on page 304 of the regular report to be followed are also to be followed in preparation of the information below.

Line No	Number & Title of Rate Schedule (a)	Kwh Sold (b)	Revenue (c)	Avg. No. Customers (d)	Kwh Sales per Cust (e)	Revenue per Kwh Sold (f)
1	**Public Street & Highway Lighting:**					
2	SPL Municipal Street Lighting	1,564,371	219,676	0	0	0.1404
3	CB Commercial	155,120	29,101	45	3,447	0.1876
4	PL Private Lighting	8,634	2,119	0	0	0.2454
5	LS Special Lighting	39,291	6,550	9	4,366	0.1667
6						
7	Total	1,767,416	257,446	54	32,730	0.1457
8						
9	**Other Sales to Public Authorities:**					
10	CB Commercial	1,286,106	169,451	84	15,311	0.1318
11	SH Small Heating	148,880	15,926	3	49,627	0.1070
12	TEB Total Electric Building	141,600	16,003	1	141,600	0.1130
13	GP General Power	2,257,370	260,479	13	173,644	0.1154
14	LS Special Lighting	43,120	5,673	1	43,120	0.1316
15	PL Private Lighting	1,884	533	0	0	0.2829
16	Total	3,878,960	468,065	102	38,029	0.1207
17						
18	**Interdepartmental**	122,455	25,805	4	30,614	0.2107
19						
20	**Sales for Resale:**					
21						
22	Municipalities	9,627,300	722,929	1	9,627,300	0.0751
23	REA Cooperatives					
24						
25	Total	9,627,300	722,929	1	9,627,300	0.0751
26						
27	Total Kansas	229,047,531	23,861,808	9,668	23,691	0.1042
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
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41						
42						

SALES OF ELECTRICITY BY KANSAS COMMUNITIES (Page 1 of 2)

1. A similar schedule in the regular report calls for sales of electricity by communities of 10,000 population or more of separate states. In the schedule below such information for the State of Kansas is to be listed for all communities served.
2. "Communities" mean: "Cities, towns, villages and cross-road communities served on other than standard rural rates."

Line No	Community (a)	RESIDENTIAL SALES (Account 440) Operating Revenue (b)	Kilowatt-hours sold (c)	Avg No of Customer/Mth (d)	COMMERCIAL & INDUSTRIAL SALES (Account 442) Operating Revenue (e)	Kilowatt-hours sold (f)	Avg No of Customer/Mth (g)
1	Baxter Springs	2,471,429	21,046,026	1,829	1,771,433	15,757,959	301
2	Camp 42	22,916	194,053	19	3,734	26,243	3
3	Corona	66,820	581,160	55	362,156	2,634,337	24
4	Columbus	1,814,415	15,650,991	1,450	1,958,992	17,235,267	261
5	Crestline	78,141	722,930	57	47,438	376,349	16
6	Galena	1,700,595	14,767,549	1,275	1,726,775	15,623,407	232
7	Hallowell	58,614	524,753	46	16,762	131,353	7
8	Lawton	32,761	306,228	23	2,801	15,234	4
9	Lowell	367,745	3,433,959	270	60,137	531,062	16
10	Melrose	22,484	206,373	18	4,227	25,566	4
11	Mineral	114,862	995,159	95	38,820	303,495	14
12	Riverton	667,373	6,284,975	466	519,788	4,559,232	75
13	Roseland	48,370	416,413	42	2,724	11,504	7
14	Scammon	246,281	2,138,356	199	55,049	395,623	23
15	Treece	0	0	0	0	0	0
16	Weir	355,655	3,020,258	288	63,704	445,773	36
17	Misc Unincorporated	3,306,715	31,466,601	2,064	819,760	6,600,177	288
18	Large Power				3,579,800	47,713,239	0
19							
20	Subtotal	11,375,176	101,755,784	8,196	11,034,100	112,385,820	1,311
21							
22	Unbilled Revenue	(26,338)	(432,646)		4,625	(57,558)	
23							
24	TOTAL	11,348,838	101,323,138	8,196	11,038,725	112,328,262	1,311
25							
26							
27							
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40							

SALES OF ELECTRICITY BY KANSAS COMMUNITIES (Page 2 of 2)

3. If sales by all Kansas communities are set forth fully in the regular report, the following schedule need not be prepared. In such cases, merely make reference to the page in the regular report where sales by Kansas communities may be found.
4. The information below should be on the same basis as provided in the schedule on page 8 of this supplement except cents may be omitted in reporting revenues and the totals for the various accounts should agree with the accounts for those accounts shown on page 8.

PUBLIC STREET AND HIGHWAY LIGHTING (Account 444)			OTHER SALES TO PUBLIC AUTHORITIES (ACCOUNT 445)			INTERDEPARTMENTAL			TOTAL			
Operating Revenue (h)	Kilowatt-hours sold (i)	Avg No of Customer/Mth (j)	Operating Revenue (k)	Kilowatt-hours sold (l)	Avg No of Customer/Mth (m)	Operating Revenue (n)	Kilowatt-hours sold (o)	Avg No of Customer/Mth (p)	Operating Revenue (q)	Kilowatt-hours sold (r)	Avg No of Customer/Mth (s)	Line No.
81,870	510,163	19	190,957	1,718,349	36	97	465		4,515,787	39,032,962	2,185	1
									26,650	220,296	22	2
									428,975	3,215,497	79	3
76,511	537,898	14	136,893	1,112,681	25				3,986,810	34,536,837	1,750	4
									125,580	1,099,279	73	5
63,608	479,044	15	106,920	847,775	15				3,597,898	31,717,775	1,537	6
									75,376	656,106	53	7
									35,562	321,462	27	8
									427,882	3,965,021	286	9
									26,711	231,939	22	10
5,086	34,651		4,634	28,671	5				163,402	1,361,976	114	11
						25,708	121,990	4	1,212,869	10,966,197	545	12
2,750	19,872		797	3,206	2				54,641	450,995	51	13
9,671	70,769	1	8,635	63,773	5				319,636	2,668,521	228	14
			0	0					0	0	0	15
17,950	115,018	5	19,067	104,505	13				456,377	3,685,554	342	16
			162		1				4,126,637	38,066,778	2,353	17
									3,579,799	47,713,237	0	18
												19
257,446	1,767,415	54	468,065	3,878,960	102	25,805	122,455	4	23,160,592	219,910,432	9,667	20
												21
									-21,711	-490,204		22
												23
257,446	1,767,415	54	468,065	3,878,960	102	25,805	122,455	4	23,138,881	219,420,228	9,667	24
												25
												26
												27
												28
												29
												30
												31
												32
												33
												34
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												39
												40

ELECTRIC EXPENSES APPLICABLE TO KANSAS OPERATIONS

1. This table should be submitted with amounts to the nearest dollar (cents omitted).
2. Reference numbers to be shown in column (g) refer to bases of allocation on page 1.
3. If more than one basis was used in the determination of any classification of expense below, the detail thereof may be submitted on a separate schedule.

			DISTRIBUTION OF EXPENSE TO KANSAS AND OTHER STATES					
			Amounts Assigned Direct			Alloc to KS		
Line No	Expense Classification and Account Numbers (a)	Total Company (b)	Kansas Only (c)	Other States (d)	Balance to be Allocated-Col (b) less cols (c) and (d) (e)	Amount (f)	Ref No (g)	Total Kansas Expense-Cols (c plus f) (h)
	OPERATION EXPENSES							
1	Power Production Expenses							
	(a) Steam Operation Exp (500-509)	37,043,141			37,043,141	1,890,190		1,890,190
	(b) Nuclear Operation Exp (517-525)	-			-	-		-
	(c) Hydraulic Operation Exp (535-540)	334,747			334,747	17,081		17,081
	(d) Other Operation Exp (546-550)	76,609,146			76,609,146	3,909,113		3,909,113
	(e) Purchased Power (555)	35,628,948			35,628,948	1,818,028		1,818,028
	(f) Sys control & Load Dispatch (556)	3,334,504			3,334,504	170,149		170,149
	(g) Other Expenses (557)	512,466			512,466	26,149		26,149
	(h) Total Power Production Oper Exp	153,462,952	-	-	153,462,952	7,830,709	39	7,830,709
2	Transmission Operation Exp (560-567)	20,848,581			20,848,581	1,058,701	40	1,058,701
3	Distribution Operation Exp (580-589)	8,488,496			8,488,496	461,162	41	461,162
4	Customer Accounts Exp (901-905)	8,353,756			8,353,756	470,016	42	470,016
5	Customer Assistance Exp (907-910)	4,035,808			4,035,808	105,754	43	105,754
6	Sales Expenses (911-916)	158,081			158,081	7,084	44	7,084
7	Adm and Gen Operating Exp (920-931)	52,571,095			52,571,095	2,970,648	50	2,970,648
8	Total Operation Expenses (Lines 1-7)	247,918,769	-	-	247,918,769	12,904,075		12,904,075
	MAINTENANCE EXPENSES							
9	Power Production Expenses							
	(a) Steam Maint Exp (510-514)	11,081,747			11,081,747	565,465		565,465
	(b) Nuclear Maint Exp (528-532)	-			-	-		-
	(c) Hydraulic Maint Exp (541-545)	404,030			404,030	20,616		20,616
	(d) Other Power Maint Exp (551-554)	13,776,204			13,776,204	702,954		702,954
	(e) Total Power Production Maint Exp	25,261,981	-	-	25,261,981	1,289,036	39	1,289,036
10	Transmission Maintenance Exp (568-573)	4,176,994			4,176,994	212,110	40	212,110
11	Distribution Maintenance Exp (590-598)	16,402,152			16,402,152	891,095	41	891,095
12	Maintenance of General Plant (935)	592,028			592,028	33,454	50	33,454
13	Total Maintenance Expenses (lines 9-12 incl)	46,433,155	-	-	46,433,155	2,425,694		2,425,694

(a) Allocation on the basis of the ration of total Company production expense by category to total production expense.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) Kansas Only

1. This table should be submitted with amounts to the nearest dollar (cents omitted).
2. Amounts shown hereunder shall be as of the year end. Show in column (e) references to allocation bases set forth on page 1 of this Supplemental Report.

Line No	ITEM (a)	Applicable to Kansas: Total Company (b)	Assigned Direct (c)	Allocated: Amount (d)	Ref No (e)	Common to Kansas and Other States (f)
	DEPRECIATION EXPENSE (403) BY FUNCTIONAL CLASSIFICATION					
1	Steam Production Plant	22,178,069		1,035,049	23	22,178,069
2	Nuclear Production Plant	-				-
3	Hydraulic Production Plant	188,008		8,774	23	188,008
4	Other Production Plant	12,678,439		591,702	23	12,678,439
5	Transmission Plant	7,484,007		374,343	24	7,484,007
6	Distribution Plant	30,123,611		1,665,655	25	30,123,611
7	General Plant	2,979,164		155,627	26	2,979,164
8	Total Depreciation Expenses (403)	75,631,298		3,831,150		75,631,298
	AMORTIZATION EXPENSES (404 & 405)					
9	Amortization of limited-term electric plant (404)	3,462,768		180,890	27	3,462,768
10	Amortization of other electric plant (405)	-				-
11	Total Amortization Expenses (Accounts 404 & 405)	3,462,768		180,890		3,462,768

Remarks:

Depreciation Expense does not include $0 in Missouri Regulatory Plan Amortization.

TAXES CHARGED - KANSAS OPERATIONS ONLY - (Accounts 408-411, inclusive)

1. This table should be submitted with amounts to the nearest dollar (cents omitted).
2. Figures herein should represent the portion applicable to Kansas of all taxes for the calendar year, by classes, which are charged to Account 408-411 inclusive, "Taxes".
3. In column (a), be specific and thorough in describing all classes of taxes.
4. Provide subheadings for the various accounts.
5. If any class of taxes is allocated on a basis other than any shown on page 1, explain fully, properly referenced, either in a footnote or an insert.

Line No	Class of Tax (a)	Applicable to Kansas Oper (Elec): Assigned Direct (b)	Allocated: Amount (c)	Allocated: Ref No (d)	Common to Kansas and Other States (e)
1	Account 408:				
2	Taxes Other Than Income Taxes				
3	Federal - Old Age Benefit		207,729	52	3,662,534
4	- Unemployment		2,369	52	41,769
5	- Environmental		-	53	
6	State - Unemployment		4,396	52	77,503
7	- Corporate Franchise		1,223	54	27,010
8	- Real and Personal		1,182,905	51	22,644,309
9					
10	County - Real and Personal		-	51	-
11					
12	City - Real and Personal		-	51	-
13	- Franchise		-	54	-
14	- Merchants		444,236	54	9,813,554
15					
16	TOTAL ACCOUNT 408		1,842,858		36,266,679
17					
18	Account 409.1:				
19	Income Taxes - Federal		46,123	56	2,154,611
20	- State		61,291	57	2,863,190
21					
22	TOTAL ACCOUNT 409.1		107,414		5,017,801
23					
24	Account 410.1:				
25	Deferred Income Taxes		877,413	58	76,337,108
26					
27	Account 411:				
28	Provision for Deferred Income Taxes - Cr		956,487	59	3,219,563
29					
30	Account 411.4:				
31	Deferred Investment Credit				
32	Investment Credit Deferred in Prior Years - Cr		(1,642)	60	(141,239)
33					
34	TOTAL ACCOUNT 411.1		954,845		3,078,324
35					
36	TOTAL INCOME TAXES		3,782,530		120,699,912
37					
38	TOTAL TAXES CHARGED				
39					
40					

FRANCHISE REQUIREMENTS (Account 927 - Electric) - Kansas Only

1. Report below all cash payments, made to municipal or other governmental authorities and the cost of electricity, materials and other items furnished such authorities during the year without reimbursement in compliance with franchise, ordinance or similar requirements, providing all such payments, etc. have not been reported separately in a similar schedule of the regular report.
2. Give the basis of amounts entered in columns (c) and (d) for electricity supplied without charge.

Line No	Name of Municipality or Other Governmental Authority (a)	Cash Overlays (b)	Electricity Supplied Without Charge KWH (c)	Electricity Supplied Without Charge Amount (d)	Other Items Furnished Without Charge (e)	Total (f)
1						$ -
2	N/A					-
3						-
4						-
5						-
6						-
7						-
8						-
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30	TOTAL		-	$ -		$ -

MONTHLY ELECTRIC PLANT INVESTMENT DATA

1. This table may be submitted to the nearest dollar, if desired.
2. When plant represented by construction work orders has been place into service and the aggregate costs thereof have been substantially determined, but the amounts applicable to primary plant accounts can not be promptly ascertained, it is preferable for reporting purposes below to show the balance of such work orders in Account 106 - Completed Construction - Not Classified (rather than in Account 107 - Construction Work in Progress).
3. The average for the year for each column should be computed as follows: Multiply by 2 the sum of the amounts shown in lines 2 to 12, inclusive. To this product add the amounts shown in lines 1 and 13. Then divide such total by 24. The result is the average of the monthly averages.

		Construction Work in Progress (Account 107)		Electric Plant in Service			Accum Provision for Depreciation of Electric Plant in Service (Account 108)	
				Located in Kansas				
Line No	Account Balance Month Ending (a)	Located in Kansas (b)	Total Company (c)	Comp Const Not Classified (Account 106) (d)	Plant in Svc Classified (Account 101) (e)	Total Company (Acct 101-106) (f)	Located in Kansas (g)	Total Company (h)
1	Previous Year December 31	1,707,849	28,484,444	479,562,317	2,232,640,419	2,712,202,737	Provision for Depreciation not Segregated by States Monthly	827,772,405
2	January 31	1,962,257	23,695,232	490,135,353	2,233,053,063	2,723,188,416		832,509,169
3	February 28	2,237,279	24,661,584	491,906,319	2,235,984,850	2,727,891,169		838,681,164
4	March 31	2,293,864	29,528,133	486,348,825	2,244,599,359	2,730,948,184		843,691,016
5	April 30	2,455,519	31,609,496	489,520,325	2,248,146,202	2,737,666,527		849,551,865
6	May 31	1,023,764	31,181,639	489,693,162	2,254,649,979	2,744,343,141		853,521,618
7	June 30	1,589,408	28,122,060	500,392,461	2,252,808,233	2,753,200,694		855,959,373
8	July 31	1,766,149	29,356,373	500,876,374	2,258,071,890	2,758,948,264		861,508,485
9	August 31	1,715,304	31,975,785	475,411,259	2,285,807,836	2,761,219,095		863,141,448
10	September 30	2,081,417	34,912,938	469,464,307	2,294,836,908	2,764,301,216		867,635,819
11	October 31	2,101,027	37,997,968	470,874,811	2,297,342,354	2,768,217,164		872,287,494
12	November 30	2,209,677	43,146,517	474,731,251	2,293,568,724	2,768,299,976		873,137,990
13	December 31	1,674,437	31,763,912	479,034,352	2,307,210,641	2,786,244,993		875,172,754
14	Avg for Year	**1,927,234**	**31,359,325**	**484,887,732**	**2,264,066,244**	**2,748,953,976**		**855,258,168**

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS - Kansas Only

Table 1

1. Report below the information called for concerning distribution watt-hours meters and line transformers.
2. Watt-hour demand distribution meters should be included below but external demand meters should not be included.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of leasor, date an period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether leasor, co-owner, or other party is an associated company.

Line No	Item (a)	Number of watt-hour meters (b)	Line Transformers Number (c)	Line Transformers Total Capacity (KVA) (d)
1	Number at Beginning of Year	10,036	5,805	187,354
2	Additions During the Year:			
3	Purchases			
4				
5	Total Additions	0	0	0
6	Reductions During Year:			
7	Retirements			
8	Associated with Utility Plant Sold			
9	Total Reductions	0	0	0
10	Number at End of Year	10,036	5,805	187,354
11	In Stock	375	145	6,094
12	Locked-Meters on Customers' Premises			
13	Inactive Transformers on System			
14	In Customers' Use	110,564	5,822	181,260
15	In Company's Use	22		
16	Total End of Year (as above)	110,961	5,967	187,354

Footnotes:

TESTING OF DISTRIBUTION METERS

Table 2

Kansas Only

1. Number of distribution meters tested during year: 311 Single Phase, 80 Multiphase
2. Number thereof which tested more than 2% slow:
3. Number thereof which tested more than 2% fast: 0 Single Phase, 0 Multiphase
4. Explain test schedules:
   Single phase meters - sample test
   Three phase and others
   (1) 50,000 Kwh usage & 0-1,000 Kw demand and greater-8 years
   (2) All other three phase-16 years.

DISTRIBUTION OF SALARIES AND WAGES

1. Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided.
2. In determining this segregation of salaries and wage originally charged to clearing accounts , a method of approximation giving substantially correct results may be used.

Line No	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	1,354,442		
4	Transmission	157,277		
5	Distribution	568,299		
6	Customer Accounts	551,897		
7	Customer Service and Informational	157,219		
8	Sales	11,208		
9	Administrative and General	1,602,309		
10	TOTAL Operation (Total of Lines 3 thru 9)	**4,402,652**		
11	Maintenance			
12	Production	742,727		
13	Transmission	153,880		
14	Distribution	464,032		
15	Administrative and General	20,339		
16	TOTAL Maint (Total of Lines 12 thru 15)	**1,380,978**		
17	Total Operation and Maintenance			
18	Production (Total of Lines 3 and 12)	2,097,169		
19	Transmission (Total of Lines 4 and 13)	311,156		
20	Distribution (Total of Lines 5 and 14)	1,032,332		
21	Customer Accounts (Line 6)	551,897		
22	Customer Service and Informational (Line 7)	157,219		
23	Sales (Line 8)	11,208		
24	Administrative and General (Total of Lines 9 and 15)	1,622,648		
25	Total Oper and Maint (Total of Lines 18 thru 24)	**5,783,629**	115,881	**5,899,510**

DISTRIBUTION OF SALARIES AND WAGES - Continued

Line No	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
26	Gas			
27	Operation			
28	Production - Manufactured Gas			
29	Production - Nat Gas (Including Expl & Dev)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Total of Lines 28 thru 37)	-	-	-
39	Maintenance			
40	Production - Manufactured Gas			
41	Production - Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint (Total of Lines 40 thru 46)	-	-	-

DISTRIBUTION OF SALARIES AND WAGES - Continued				
Line No	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
48	Total Operation and Maintenance			
49	Production - Manufactured Gas (Lines 28 and 40)	-		
50	Production - Nat Gas (Including Expl and Dev)			
	(Lines 29 and 41)	-		
51	Other Gas Supply (Lines 30 and 42)	-		
52	Storage, LNG Terminaling and Processing			
	(Lines 31 and 43)	-		
53	Transmission (Lines 32 and 44)	-		
54	Distribution (Lines 33 and 45)	-		
55	Customer Accounts (Lines 34)	-		
56	Customer Service and Informational (Line 35)	-		
57	Sales (Line 36)	-		
58				
59	TOTAL Op and Maint (Total of Lines 49 thru 58)	-		
60	Other Utility Departments			
61	Operation and Maintenance	34,566	2,147	36,713
62	TOTAL All Utility Dept (Total of lines 25,59 & 61)	**5,818,195**	**118,028**	**5,936,223**
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	1,024,059	654,022	1,678,081
66	Gas Plant			-
67	Other	3,967	(118)	3,849
68	TOTAL Construction (Total of lines 65 thru 67)	**1,028,026**	**653,904**	**1,681,930**
69	Plant Removal (By Utility Departments)			
70	Electric Plant	214,948	137,292	352,240
71	Gas Plant			-
72	Other	438	(13)	425
73	Total Plant Removal (Total of lines 70 thru 72)	**215,386**	**137,279**	**352,665**

DISTRIBUTION OF SALARIES AND WAGES - Continued				
Line No	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
74	Other Accounts (Specify):			
75	Clearings	909,212	(909,212)	-
76	Other Income and Deductions	104,397	-	104,397
77				
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,013,609	(909,211)	104,397
96	TOTAL SALARIES AND WAGES	**8,075,216**	**-**	**8,075,216**

CLEAN AIR ACT AMENDMENTS OF 1990

	Number	Price	Amount
Allowances purchased during the year			
Allowances sold during the year	167	0.0632335	10.56
	167	0.0149700	2.50

	Year(s)
For allowances purchased, state year or years to which purchases pertain	
For allowances sold, state year or years of which sales pertain	2017
	2024

Annual Report of The Empire District Electric Company	Year Ending December 31, 2017

VERIFICATION

The foregoing report must be verified by the oath of the President or chief officer of the company. The oath required may be taken before any person authorized to administer an oath by the laws of the State in which the same is taken.

OATH

State of Missouri)
) SS:
County of Jasper)

_______________ makes oath and says that
(Insert here the name of the affiant)

he/she is Vice-President of Finance & Administration
(Insert here the exact legal title or name of the respondent)

That he/she has examined the foregoing report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the said report are true and the said report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from the including.

January 1, 2017, to and including December 31, 2017

Tisha O. Sandersen
(Signature of affiant)

Subscribed and sworn to before me, a Notary

In and for the State and county above named, this 24th day of April 2018.

My commission expires Nov. 16, 2018

Sherri J. Blalock
(Signature of officer authorized to administer oaths)

SHERRI J. BLALOCK
Notary Public - Notary Seal
State of Missouri, Newton County
Commission # 14969626
My Commission Expires Nov 16, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40 F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2017 **Commission File Number 001-37946**

ALGONQUIN POWER & UTILITIES CORP.

(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

354 Davis Road
Oakville, Ontario
L6J 2X1, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common shares, no par value	Toronto Stock Exchange
	The New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Common Shares, no par value
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

☒ **Annual Information Form** ☒ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2017, there were 431,765,935 Common Shares outstanding.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes ☐ **No** ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ **No** ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☒ **No** ☐

This Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant's Registration Statements on Form F-3 (File No. 333-220059), F-10 (File No. 333-216616) and Form F-8 (File Nos. 333-177418, 333-213648, 333-213650 and 333-218810) and under the Securities Act of 1933, as amended.

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2017 is filed as Exhibit 99.1 to this annual report on Form 40-F.

AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2017 are filed as Exhibit 99.2 to this annual report on Form 40-F.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis for the fiscal year ended December 31, 2017 is filed as Exhibit 99.3 to this annual report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading "Disclosure Controls and Procedures" (page 56) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2017 (the "MD&A"), filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

INTERNAL CONTROL OVER FINANCIAL REPORTING

A. Management's report on internal control over financial reporting

Management, including the chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

During the year ended December 31, 2017, the Company acquired The Empire District Electric Company ("Empire"). Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company's internal control over financial reporting. The financial information for this acquisition is included in the MD&A and in note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2017, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this assessment, management concluded that Algonquin's internal control over financial reporting was effective as of December 31, 2017 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of the Company.

B. Auditor's attestation report on internal control over financial reporting

Ernst & Young, LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2017, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2017. The attestation report is provided in Exhibit 99.2 to this annual report on Form 40-F.

C. Changes in internal control over financial reporting

The information provided under the heading "Changes in Internal Controls Over Financial Reporting" (page 56) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2017, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin's board of directors has determined that it has two audit committee financial experts serving on its audit committee. Christopher Ball and Dilek Samil have been determined to be such audit committee financial experts and are independent, as that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin and Rule 10A-3 of the Exchange Act. The SEC has indicated that the designation of Christopher Ball and Dilek Samil as audit committee financial experts does not make either of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball and Dilek Samil that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

CODE OF ETHICS

Algonquin has adopted a code of business conduct and ethics (the "Code of Conduct") that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer. The Code of Conduct is available without charge to any shareholder upon request to Ian Tharp, Telephone: (905) 465-4500, E-mail: ir@algonquinpower.com, Algonquin Power & Utilities Corp., 354 Davis Road, Oakville, Ontario L6J 2X1.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading "Pre-Approval Policies and Procedures" (page 61) in the Annual Information Form for the fiscal year ended December 31, 2017, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the years ended December 31, 2016 and 2017 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on its financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading “Contractual Obligations” (page 41) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2017, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

NON-GAAP FINANCIAL MEASURES

The terms “Adjusted Net Earnings”, “Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization” (“Adjusted EBITDA”), “Adjusted Funds from Operations”, “Net Energy Sales”, “Net Utility Sales” and “Divisional Operating Profit” are used throughout this annual report on Form 40-F, including the MD&A. The terms “Adjusted Net Earnings”, “Adjusted Funds from Operations”, “Adjusted EBITDA”, “Net Energy Sales”, “Net Utility Sales” and “Divisional Operating Profit” are not recognized measures under U.S. generally accepting accounting principles. There is no standardized measure of “Adjusted Net Earnings”, “Adjusted EBITDA”, “Adjusted Funds from Operations”, “Net Energy Sales”, “Net Utility Sales”, and “Divisional Operating Profit”; consequently, APUC’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “Adjusted Net Earnings”, “Adjusted EBITDA”, “Adjusted Funds from Operations”, “Net Energy Sales”, “Net Utility Sales”, and “Divisional Operating Profit” can be found throughout the MD&A.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC’s target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the “safe harbour” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation's acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "4. Enterprise Risk Factors" in our Annual Information Form for the fiscal year ended December 31, 2017, filed as Exhibit 99.1 to this annual report on Form 40-F.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

Algonquin has a standing Audit Committee of its board of directors established in accordance with Section 3(a)(58)(A) of the Exchange Act. The information provided under the heading "Audit Committee" (page 61) identifying Algonquin's Audit Committee and confirming the independence of the Audit Committee in the Annual Information Form for the fiscal year ended December 31, 2017, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2017 is filed as Exhibit 101 to this annual report on Form 40-F.

MINE SAFETY DISCLOSURE

Not applicable.

COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

Algonquin is subject to corporate governance requirements prescribed under applicable Canadian corporate governance practices ("Canadian Rules"). Algonquin is also subject to corporate governance requirements prescribed by the listing standards of the New York Stock Exchange ("NYSE") Stock Market, and certain rules and regulations promulgated by the SEC under the Exchange Act (including those applicable rules and regulations mandated by the Sarbanes-Oxley Act of 2002). In particular, Section 303A.00 of the NYSE Listed Company Manual requires Algonquin to have an audit committee that meets the requirements of Rule 10A-3 of the Exchange Act, and Section 303A.011 of the NYSE Listed Company Manual requires Algonquin to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies listed on the NYSE. A description of those differences follows.

Section 303A.01 of the NYSE Listed Company Manual requires that boards have a majority of independent directors and Section 303A.02 defines independence standards for directors. Algonquin's Board of Directors is responsible for determining whether or not each director is independent. In making this determination, the Board of Directors has adopted the definition of "independence" as set forth in the Canadian National Instrument 58-101 *Disclosure of Corporate Governance Practices*. In applying this definition, the Board of Directors considers all relationships of its directors, including business, family and other relationships. Algonquin's Board of Directors also determines whether each member of its Audit Committee is independent pursuant to National Instrument 52-110 *Audit Committees* and Rule 10A-3 of the Exchange Act.

Section 303A.04(a) of the NYSE Listed Company Manual requires that all members of the nominating/corporate governance committee be independent. Algonquin's Corporate Governance Committee includes one director who is not independent, but the Committee has appointed a Nominating Sub-Committee consisting solely of independent directors that performs all responsibilities relating to the director nominations process.

Section 303A.05(a) of the NYSE Listed Company Manual requires that all members of the compensation committee be independent.

Section 303A.07(b)(iii)(A) of the NYSE Listed Company Manual requires, among other things, that the written charter of the audit committee state that the audit committee at least annually, obtain and review a report by the independent auditor describing the firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues. The written charter of the audit committee complies with Canadian Rules, but does not explicitly state that these functions are part of the purpose of the audit committee, which is not required by Canadian Rules.

Section 303A.08 of the NYSE Listed Company Manual requires that shareholders of the listed company be given the opportunity to vote on all equity-compensation plans and material revisions thereto. Canadian Rules generally require that shareholders approve all equity compensation plans, but the Canadian Rules are not identical to the NYSE Rules. Algonquin complies with Canadian Rules.

Section 303A.09 of the NYSE Listed Company Manual requires that listed companies adopt and disclose corporate governance guidelines that address certain topics, including director compensation guidelines. Algonquin has adopted its Board Mandate, which is the equivalent of corporate governance guidelines, in compliance with the Canadian Rules. Algonquin's corporate governance guidelines do not address director compensation, but Algonquin provides disclosure about the decision making process for non-employee director compensation in the annual management information circular and Algonquin has adopted a policy on share ownership guidelines for non-employee directors.

Section 303A.10 of the NYSE Listed Company Manual requires that a listed company's code of business conduct and ethics mandate that any waiver of the code for executive officers or directors may be made only by the board or a board committee and must be promptly disclosed to shareholders. Algonquin's code of business conduct and ethics complies with Canadian Rules and does not include such a requirement.

UNDERTAKING

Algonquin undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Algonquin previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.

Any change to the name or address of the agent for service of Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 7, 2018

By:	/s/ David Bronicheski
Name:	David Bronicheski
Title:	Chief Financial Officer

EXHIBIT INDEX

99.1	Annual Information Form for the year ended December 31, 2017.
99.2	Audited Annual Financial Statements for the year ended December 31, 2017.
99.3	Management's Discussion & Analysis for the year ended December 31, 2017.
99.4	Consent Letter from Ernst & Young, LLP.
99.5	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.6	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM
For the year ended December 31, 2017

March 7, 2018

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Caution Concerning Forward-looking Statements and Forward-looking Information

This document may contain statements that constitute “forward-looking statements” or “forward-looking information” within the meaning of applicable securities legislation (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to: expectations regarding earnings and cash flow; statements relating to renewable energy credits expected to be generated and sold; tax credits expected to be available and/or received; the expected timeline for regulatory approvals; expectations with respect to the completion of the Atlantica transaction; the expected approval timing and purchase price of the Perris water distribution system transaction; the expected closing timing and amount of indebtedness to be assumed in relation to the St. Lawrence Gas Company, Inc. transaction; expectations and plans with respect to the Granite Bridge project; expectations with respect to revenues pursuant to energy production hedges; expected completion dates for projects under construction; expectations with respect to the Asbury Coal Power Plant; expected timing of post-closing adjustments related to the Long Sault Hydro Facility; the resolution of legal and regulatory proceedings; expected demand for renewable sources of power; government procurement opportunities; expected capacity of and energy sales from new energy projects; expected use of proceeds from the sale of common shares; business plans for APUC subsidiaries; and expected future base rates. All forward-looking information is given pursuant to the “safe harbour” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation’s facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify appropriate projects to maximize the value of PTC qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions; Atlantica or the Corporation's anticipated joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "Enterprise Risk Factors".

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms "Net Utility Sales", "Net Energy Sales" and "Adjusted EBITDA" are used throughout this AIF. These terms are not recognized measures under GAAP. There is no standardized measure of "Net Utility Sales", "Net Energy Sales" or "Adjusted EBITDA"; and consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Net Utility Sales", "Net Energy Sales" and "Adjusted EBITDA" can be found in APUC's MD&A for the year ended December 31, 2017 (which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar) under the headings "Liberty Power Group – 2017 Liberty Power Group Operating Results", "Liberty Utilities Group – 2017 Fourth Quarter Operating Results", "2017 Annual Operating Results", and "Non-GAAP Performance Measures – Reconciliation of Adjusted EBITDA to Net Earnings". Such calculations and analysis are incorporated by reference herein.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Corporation. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. ("**APUC**") was originally incorporated under the *Canada Business Corporations Act* on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the Corporation amended its articles to change its name to Société Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the Corporation, among other things, created a new class of common shares, transferred its existing operations to a newly formed independent corporation, exchanged new common shares for all of the trust units of Algonquin Power Co. ("**APCo**") and changed its name to Algonquin Power & Utilities Corp. The head and registered office of APUC is located at Suite 100, 354 Davis Road, Oakville, Ontario, L6J 2X1.

Unless the context indicates otherwise, references in this AIF to the "**Corporation**" refer collectively to APUC, its direct or indirect subsidiary entities and partnership interests held by APUC and its subsidiary entities.

1.2 Intercorporate Relationships

Most of the Corporation's business is conducted through subsidiary entities, including those entities which hold project assets. The table on the following page excludes certain subsidiaries. The assets and revenues of the excluded subsidiaries did not individually exceed 10%, or in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2017. The voting securities of each subsidiary are held in the form of common shares, share quotas or partnership interests in the case of partnerships and their foreign equivalents, and units in the case of trusts.

The subsidiaries of APUC are grouped into two primary North American business units of the Corporation consisting of the Liberty Power Group and the Liberty Utilities Group. The following chart summarizes the major lines of business:

Liberty Power Group	Liberty Utilities Group
Hydro Electric Generation Solar Generation Thermal Co-Generation Wind Power Generation	Electric Utilities Natural Gas Utilities Water & Wastewater Utilities Natural Gas and Electric Transmission

Additional information on selected facilities owned by these business units is described in Schedules A, B, C, D, and E.

The following table outlines the Corporation's significant subsidiaries:

Significant Subsidiaries	Description	Jurisdiction	Ownership of Voting Securities
LIBERTY POWER GROUP			
Algonquin Power Co. (dba Liberty Power)		Ontario	100%
St. Leon Wind Energy LP ("**St. Leon LP**")	Owner of the St. Leon Wind Facility	Manitoba	100%
Algonquin Power Windsor Locks LLC	Owner of Windsor Locks Facility	Connecticut	100%
Minonk Wind, LLC	Owner of the Minonk Wind Facility	Delaware	100%[1]
Senate Wind, LLC	Owner of the Senate Wind Facility	Delaware	100%[1]
GSG6, LLC	Owner of the Shady Oaks Wind Facility	Illinois	100%
Odell Wind Farm, LLC	Owner of the Odell Wind Facility	Minnesota	100%[1]
Deerfield Wind Energy, LLC	Owner of the Deerfield Wind Facility	Delaware	100%[1]
LIBERTY UTILITIES GROUP			
Liberty Utilities (Canada) Corp. ("**LU Canada**")		Canada	100%
Liberty Utilities Co.		Delaware	100%
Liberty Utilities (CalPeco Electric), LLC	Owner of the CalPeco Electric System	California	100%
Liberty Utilities (Granite State Electric) Corp.	Owner of the Granite State Electric System	New Hampshire	100%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	Owner of the EnergyNorth Gas System	New Hampshire	100%
Liberty Utilities (Midstates Natural Gas) Corp.	Owner of natural gas distribution utility assets in Missouri, Iowa and Illinois	Missouri	100%
Liberty Utilities (Peach State Natural Gas) Corp.	Owner of the Peach State Gas System	Georgia	100%
Liberty Utilities (New England Natural Gas Company) Corp.	Owner of the New England Gas System	Delaware	100%
Liberty Utilities (Park Water) Corp. ("**Liberty Park Water**")	Owner of the Liberty Park Water System in Downey, California	California	100%
Liberty Utilities (Apple Valley Ranchos Water) Corp. ("**Apple Valley**")	Owner of the Apple Valley Water System	California	100%
The Empire District Electric Company ("**Empire**")	Owner of (i) electric and water distribution utility assets serving locations in Missouri, Kansas, Oklahoma and Arkansas, (ii) the Ozark Beach hydro facility in Missouri, the Riverton, Energy Center, and Stateline No. 1 natural gas-fired power generation facilities in Kansas and Missouri, the Asbury coal-fired power generation facility in Missouri and a 40% interest in the Stateline combined cycle gas facility in Missouri, and (iii) certain other generation facility and PPA interests.	Kansas	100%
The Empire District Gas Company	Operator of a natural gas distribution utility in Missouri	Kansas	100%
Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Owner of the LPSCo System	Arizona	100%

[1] The Corporation holds 100% of the managing interests, with 100% of the non-managing interests held by third party partners.

2. GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flow to support a growing dividend and share price appreciation. APUC also strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

The Corporation's operations are organized across two primary North American business units: the Liberty Power Group and the Liberty Utilities Group.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities and/or projects.

Liberty Utilities Group

The Liberty Utilities Group operates diversified regulated electricity, natural gas, water distribution and wastewater collection utility services. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

2.1 Three Year History and Significant Acquisitions

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

2.1.1 Fiscal 2015

Corporate

(i) $150 Million Bought Deal Offering of Common Shares

On December 2, 2015, APUC issued, on a bought deal basis, 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150 million. Net proceeds of the offering were used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

Liberty Power Group

(i) Deerfield Wind Project Joint Venture

On October 19, 2015, the Liberty Power Group announced it had agreed to jointly develop the 150 MW Deerfield Wind Facility in Michigan with Renewable Energy Systems Americas Inc.

(ii) Great Bay Solar Project

On December 1, 2015, the Liberty Power Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County, Maryland. The facility is contracted under a 10 year PPA. The facility will also generate solar RECs which will be sold into the Maryland market. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Business Development"* below.

(iii) Completion of Bakersfield I Solar Project

On April 14, 2015, the Liberty Power Group achieved commercial operation of the 20 MW Bakersfield I Solar Facility located in Kern County, California. The electricity generated by the project is being sold under a 20 year PPA with a large investment grade electric utility. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Solar Power Generating Facilities"* below.

Liberty Utilities Group

(i) Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million.

(ii) U.S. Debt Private Placement

On April 30, 2015, the Liberty Utilities Group financing entity entered into a note purchase agreement for the issuance of U.S. $160 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing were used to partially finance the acquisition of the Liberty Park Water System and for general corporate purposes. The notes were issued in two tranches: U.S. $90 million were issued immediately on closing and U.S. $70 million were issued on July 15, 2015. The notes were assigned a rating of BBB High by DBRS. The financing was the fourth series of notes issued pursuant to the Corporation's master indenture.

2.1.2 Fiscal 2016

Corporate

(i) Financing Related to the Empire Acquisition

In the first quarter of 2016, in connection with the acquisition of Empire (the "**Empire Acquisition**") discussed below, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("**Debentures**") of APUC (the "**Debenture Offering**") and also obtained U.S. $1.6 billion in acquisition financing commitments from a syndicate of banks (the "**Empire Acquisition Facility**"). For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(ii) Dual Listing of Algonquin Common Shares on the New York Stock Exchange

During the fourth quarter of 2016, APUC received approval to list the Common Shares for trading on the NYSE under the ticker symbol "AQN". The Corporation has been a U.S. Securities and Exchange Commission registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the TSX also under the ticker symbol "AQN".

(iii) U.S. $235 Million Corporate Term Credit Facility

On January 4, 2016, the Corporation entered into a U.S. $235 million term credit facility with two U.S. banks. The proceeds of the term credit facility provided additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018.

Liberty Power Group

(i) Acquisition of 75% interest in the Red Lily Energy Partnership

Effective April 12, 2016, the Liberty Power Group exercised its option to subscribe for a 75% equity interest in the Red Lily Wind Energy Partnership, a 26.4 MW wind energy facility (the "**Red Lily Wind Facility**") located in southeastern Saskatchewan for which the Liberty Power Group provides operation and supervision services.

(ii) Completion of the Odell Wind Facility

On July 29, 2016, the 200 MW Odell Wind Facility achieved commercial operation. On August 5, 2016, the tax equity financing of approximately U.S. $180 million was completed and on September 15, 2016 the Liberty Power Group acquired control of the project. The Odell Wind Facility has a 20 year PPA with a large investment grade utility. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities"* below.

(iii) Purchase of Turbines to Safe Harbour Production Tax Credit Rate

At the end of 2016, the Liberty Power Group purchased approximately $75 million of turbine components that will qualify between 500 MW and 700 MW of new projects for 100% of the production tax credit ("**PTC**"). The full PTC is approximately U.S. $23 per MWh and subject to an annual adjustment for inflation. The PTC at the full rate is available to projects in the United States completed before the end of 2020 if they commenced construction prior to December 31, 2016 or have purchased components that qualify under the Internal Revenue Service safe harbor rules ("**Full PTC Projects**"). Projects other than Full PTC Projects will receive 80% of the applicable PTC rate if construction commences in 2017, 60% if construction commences in 2018, and 40% if construction commences in 2019. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Liberty Power Group is currently evaluating projects to maximize the value of this equipment.

Liberty Utilities Group

(i) Acquisition of the Liberty Park Water System

On January 8, 2016, the Liberty Utilities Group closed a previously announced agreement to acquire a regulated water distribution utility holding company, Park Water Company, now known as Liberty Utilities (Park Water) Corp. (the "**Liberty Park Water System**"). The Liberty Park Water System owns and operates two regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and, at the time of closing, owned one regulated water utility in western Montana. Total consideration for the utility purchase was U.S. $341.3 million, which includes the assumption of approximately U.S. $91.8 million of existing debt.

The water utility located in western Montana was the subject of a condemnation lawsuit filed by the city of Missoula and has been the subject of certain related litigation and regulatory proceedings. Please see "*Legal Proceedings and Regulatory Actions - Regulatory Actions*" for a detailed description and discussion.

(ii) Successful Rate Case Outcomes

During 2016, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $21.4 million.

2.1.3 Fiscal 2017

Corporate

(i) Completion of Financing Related to the Empire Acquisition

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

Following the closing of the Empire Acquisition, the final instalment date was established as February 2, 2017 at which time APUC received the final instalment payment. To date, almost all of the Debentures had been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Empire Acquisition Facility. For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(ii) Extension of Dividend Reinvestment Plan

The Corporation announced on August 21, 2017 that eligible shareholders resident in the United States had then become able to enroll their Common Shares in the Corporation's shareholder dividend reinvestment plan (the "**Reinvestment Plan**"). Since its launch in 2011, the Reinvestment Plan was previously only available to residents of Canada.

(iii) Formation of Global Clean Energy and Water Infrastructure Joint Venture and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC announced that it had entered into (a) a memorandum of understanding to create a joint venture ("**AAGES**") with Seville, Spain-based Abengoa S.A. ("**Abengoa**") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the agreement to create the AAGES joint venture, APUC announced that it had entered into a definitive agreement to purchase from Abengoa an indirect 25% equity interest in Atlantica Yield plc ("**Atlantica**") for a total purchase price of approximately U.S. $608 million, or U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018. Closing is subject to customary closing conditions.

(iv) Bought Deal Offering of Common Shares

Coincident with the announcement of the Abengoa/Atlantica transaction on November 1, 2017, APUC announced a bought deal offering of Common Shares. The offering, including the exercise in full of the underwriters' over-allotment option, closed on November 10, 2017. A total of 43,470,000 Common Shares were sold at a price of $13.25 per share for gross proceeds of approximately $576 million.

(v) Corporate Credit Facilities

During the third quarter of 2017, the Corporation's senior unsecured bilateral revolving facility was increased from $65 million to $165 million and the maturity was extended to November 19, 2018. During the fourth quarter of 2017, the Corporation entered into a term credit agreement in the amount of U.S. $600 million with a maturity of December 21, 2018 to support the closing of its transactions with Abengoa and Atlantica, as described above.

Liberty Power Group

(i) Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $300 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. The net proceeds were used to partially finance the Odell Wind Facility, Deerfield Wind Facility and Bakersfield II Solar Facility.

(ii) Completion of Deerfield Wind Facility

On February 21, 2017, 150 MW Deerfield Wind Facility achieved commercial operation, on March 14, 2017, the Liberty Power Group acquired the remaining 50% interest in the project, and on May 10, 2017, tax equity financing of approximately U.S. $167 million was completed. The project has a 20 year PPA with a local electric distribution utility.

(iii) Great Bay Solar Project

On September 18, 2017, the Liberty Power Group entered into an equity capital contribution agreement with a third-party tax equity investor for a non-controlling interest in the Great Bay Solar Project. The tax equity investor will fund approximately U.S. $59 million.

(iv) Credit Facilities

On April 19, 2017, the Liberty Power Group entered into a $150 million senior unsecured bilateral revolving credit facility maturing on August 19, 2018. On October 6, 2017, the Liberty Power Group's syndicated revolving credit facility was increased from $350 million to U.S. $500 million and the maturity was extended to October 6, 2022.

Liberty Utilities Group

(i) Completion of the Empire District Electric Acquisition

On January 1, 2017, the Liberty Utilities Group successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. $2.4 billion including the assumption of approximately U.S. $0.9 billion of debt. Empire is a Joplin, Missouri based regulated electric, gas and water utility serving customers in Missouri, Kansas, Oklahoma, and Arkansas.

For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below. APUC has filed a business acquisition report dated March 10, 2017 in respect of the Empire Acquisition which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

(ii) Completion of Financing Related to the Empire Acquisition

On March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue U.S. $750 million of senior unsecured notes by way of private placement. The notes are of varying maturities ranging from 3 to 30 years with a weighted average life of approximately 15 years and an effective weighted average interest expense of 3.6% (inclusive of interest rate hedges). The closing of the offering occurred on March 24, 2017, with the proceeds used to repay the balance of the Empire Acquisition Facility and other existing indebtedness. For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(iii) Completion of the Luning Solar Project

On February 15, 2017, the Liberty Utilities Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada (the "**Luning Facility**") for approximately U.S. $110.9 million. On February 17, 2017, the final tranche of the tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the project is included in the rate base of the CalPeco Electric System as energy produced from the project is being consumed by the utility's customers.

(iii) Approval to Acquire Perris Water Distribution System

On August 10, 2017, the Board approved the acquisition of two water distribution systems from the City of Perris, California for an anticipated purchase price of U.S. $11.5 million. The Perris City council approved the sale to the Liberty Utilities Group in July 2017 and the city's residents approved the sale on November 7, 2017. Approval of the acquisition by the CPUC is expected in 2018.

(iv) Definitive Agreement to Acquire St. Lawrence Gas Company, Inc.

On August 31, 2017, the Liberty Utilities Group announced the entering into of a definitive agreement with Enbridge Gas Distribution Inc., a subsidiary of Enbridge Inc., to acquire St. Lawrence Gas Company, Inc. ("**SLG**"), a regulated natural gas distribution utility located in northern New York State, and its subsidiaries. The proposed transaction is structured as a stock purchase in exchange for a cash purchase price of U.S. $70 million less the total amount of outstanding SLG indebtedness (which will be assumed by the Liberty Utilities Group at closing and is currently expected to be approximately U.S. $10 million), and is subject to customary working capital adjustments. Closing of the acquisition remains subject to regulatory approval and other customary closing conditions, and is expected to occur in 2018.

(v) Granite Bridge Project Announcement

On December 4, 2017, the Liberty Utilities Group announced plans for a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

(vi) Successful Rate Case Outcomes

During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million.

2.1.4 Recent Developments - 2018

Corporate

(i) Change to U.S. Dollar Reporting

APUC has determined that, effective with the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Liberty Power Group

(i) Increase to Letter of Credit Facility

On February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200 million. The facility continues to be a one year extendible facility.

Liberty Utilities Group

(i) Liberty Utilities Credit Facilities

On February 23, 2018, the Liberty Utilities Group increased availability under its senior unsecured syndicated revolving credit facility from U.S. $200 million to U.S. $500 million and extended the maturity of such facility to 2023. The Liberty Utilities Group simultaneously canceled its U.S. $200 million revolving credit facility at Empire.

(ii) Pending Rate Case Filings

The Liberty Utilities Group has pending rate case filings in progress that represent an increase in rates in the amount of U.S. $44.4 million which are expected to be completed in 2018.

3. DESCRIPTION OF THE BUSINESS

3.1 Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean power facilities located across North America. The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 87% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which as of December 31, 2017 had a production-weighted average remaining contract life of approximately 15 years. Details with respect to the Liberty Power Group's significant facilities and the term of material PPAs is set out in Schedules A and B.

3.1.1 Regulatory Regimes - Power Generation

(i) Canada

Much of the electricity supplied within the Canadian provinces is generated by government-owned corporations, such as OPG and Hydro-Québec. Independent power producers, such as the Corporation, provide additional capacity and supply to the grids. In Canada, the provinces have legislative authority over the generation, transmission and distribution of electricity. This in turn means that each province may have different requirements for the business to comply with in respect of the projects it owns in each province.

Generally speaking, each province in which the Corporation operates has various pieces of legislation in effect with which the business must comply. These relate to the generation, transmission and distribution of electricity in the province, the administration of the electric system, as well as the creation and authority of various governmental agencies who have oversight of an aspect of the industry, such as the ISO and the provincial energy board, utilities commission or other similar authority responsible for rate-making and regulatory oversight of the industry. In addition, some provinces require a generator of electricity to be licensed and registered with the appropriate governmental authority and the Corporation must comply with the conditions of license or registration accordingly. In addition to the legal requirements, the system operators have promulgated market rules to be complied with within their operating jurisdictions and any codes, rules and standards of the applicable energy board or utilities commission must be complied with.

(ii) United States

The power generation industry in the United States is regulated by the FERC under the U.S. Federal Power Act ("**FPA**"), the Energy Policy Act of 2005, the Public Utilities Regulatory Policies Act and the Public Utility Holding Company Act of 2005 ("**PUHCA**").

(1) Rate Regulation

All of the Liberty Power Group's operating U.S. power generation facilities are either: (1) exempt wholesale generators ("**EWGs**"); or (2) qualifying small power or cogeneration facilities ("**QFs**"). EWGs sell electricity exclusively in wholesale markets, while QFs with a power production capacity of 20 MW or less are exempt from most regulation under the FPA. There are two types of QFs: (1) qualifying small power production facilities; and (2) qualifying cogeneration facilities. In order to be a qualifying small power production facility, which includes hydro, geothermal, solar and biomass, the facility must meet the maximum size and fuel use criteria specified in FERC's regulations. In order to be a qualifying cogeneration facility, the facility must meet the operating and efficiency criteria specified in FERC's regulations. All of the Liberty Power Group's operating U.S. power generation facilities that are EWGs possess FERC authorization to engage in sales for resale at market-based rates ("**MBR Authority**"). The QFs with a capacity greater than 20 MW also possesses MBR Authority. QFs with a capacity of 20 MW or less are not required to possess MBR Authority for their power sales, unless they are within a certain geographic proximity of one another. MBR Authority is available to EWGs and certain QFs and is obtained by showing that the generator and its affiliates do not possess vertical or horizontal market power in the relevant market. Once MBR Authority is obtained, the EWG or QF with a capacity greater than 20 MW, may sell its power into the relevant market at market-based rates. Each entity with MBR Authority must report its sales into the market by filing quarterly reports which details the relevant contracts used to sell power and the rates obtained for such power sales. QFs with a capacity of 20 MW or less are not required to file quarterly reports.

(2) NERC

The Energy Policy Act of 2005 expanded FERC's authority to impose mandatory reliability standards on the bulk electric system and to impose penalties on entities that manipulate the electric and natural gas markets. On June 20, 2006, NERC was certified by FERC as the Electric Reliability Organization for North America. NERC's mission is to ensure the reliability and security of the North American Bulk Electric System. NERC accomplishes its mission through enforcement of mandatory regulation of reliability operating standards. NERC also annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is subject to oversight by FERC and governmental authorities in Canada. Some assets of the Liberty Power Group and the Liberty Utilities Group are subject to regulation by NERC.

(3) PUHCA

The Corporation is also subject to the PUHCA. PUHCA and FERC's implementing regulations impose certain books, records and accounting requirements on public utility holding companies. APUC is a public utility holding company and subject to such regulations. The Liberty Power Group's intermediate holding companies claims exemption from PUCHA under Title 18, Part 366.3 of the U.S. Code of Federal Regulations, which provides that a company that is a holding company solely by virtue of holding interests in QFs, EWGs and foreign utility companies is exempt from the books, records and accounting provisions of PUHCA and FERC's associated regulations. Should any of the EWGs or QFs cease qualifying for such status by no longer meeting the regulatory requirements for qualification, then the exemption would no longer apply. At that time, the books, records and accounting requirements would then apply.

3.1.2 Description of Operations

Hydroelectric Generating Facilities

(i) Production Method

A hydroelectric generating facility consists of a number of key components, including a dam, intake structure, electromechanical equipment consisting of a turbine(s) and a generator(s). A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace, as well as to provide sufficient depth within the reservoir for an intake. Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal and an intake structure. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy. The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

(ii) Principal Markets and Distribution Methods

The principal markets in which the Liberty Power Group operates hydroelectric generating facilities in Canada are Alberta, Ontario, New Brunswick and Québec. In the U.S., the principal market is Maine. The majority of generated hydroelectricity is conveyed from the relevant facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser.

(1) Alberta

The electrical power industry in Alberta is regulated by the EUA. The AESO was established under the EUA to provide a competitive, real-time spot market for electric energy. The AESO is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the AESO.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the OEB. While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The OEFC purchases the energy generated by the Ontario facilities and holds all rights, obligations and liabilities under the existing contracts. The Corporation's relevant subsidiary entities have also received a license to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick

Effective October 1, 2013, the New Brunswick government amended the provincial Electricity Act (New Brunswick), which resulted in the re-amalgamation of the NBSO with members of NB Power, a vertically-integrated group of companies, resulting in the transmission system operation functions of the NBSO being performed by NB Power’s Transmission and System Operator division.

(4) Québec

Hydro-Québec is the primary electricity generator, transmitter, and distributor of electricity in the province of Québec; its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular large hydro, and supports the development of other technologies, such as wind energy and biomass. It also sells power on wholesale markets in northeastern North America.

(iii) Material Facilities

(1) Tinker Hydro Facility

The Tinker Hydro Facility is located approximately 8 km north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility has a total nameplate capacity of approximately 34.5 MW.

As part of the generation assets in New Brunswick and Northern Maine, the Liberty Power Group owns an electrical transmission system used to interconnect the Tinker Hydro Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick.

The output of the Tinker Hydro Facility is actively marketed together with any applicable environmental attributes less any associated transportation costs. Additional energy and applicable environmental attributes are purchased from the market to supplement the energy generated from the Tinker Hydro Facility in order to service customer demand.

(2) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 km west of the Town of Innisfail, Alberta. The Dickson Dam Hydro Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The Liberty Power Group sells all of the power generated at the Dickson Dam Hydro Facility in the AESO at market rates. The Dickson Dam Hydro Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030.

Wind Power Generating Facilities

(i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

(ii) Principal Markets and Distribution Methods

The principal markets for the Liberty Power Group's operational wind facilities in Canada are Manitoba for the St. Leon Wind Facilities, Saskatchewan for the Red Lily and Morse Wind Facilities, and Quebec for the Saint-Damase Wind Facility. The electricity generated by the wind turbines is transmitted to the transmission system of the purchaser, Manitoba Hydro in the case of the St. Leon Wind Facility and St. Leon II Wind Facility, SaskPower in the case of the Red Lily and Morse Wind Facility, and Hydro-Quebec in the case of the Saint-Damase Wind Facility. The principal markets for Liberty Power Group's wind facilities in the United States are the PJM, MISO and ERCOT regional markets.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown Investments Corporation. SaskPower has set a target of 50% of generation capacity from renewables by 2030. As a result, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Québec

Hydro-Québec's hydroelectric portfolio accounts for 99% of its electricity mix and, as such, the utility has encouraged the development of wind projects in the province in recent years.

(4) Illinois and Pennsylvania

PJM is one of ten RTOs operating in North America. PJM, acting as a neutral, independent party, operates a competitive wholesale electricity market in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

(5) Michigan and Minnesota

MISO is an ISO, similar to an RTO, operating in fifteen U.S. states and the Canadian province of Manitoba. MISO assures consumers of unbiased regional grid management and open access to the transmission facilities through their functional supervision. MISO has interconnections with PJM, ERCOT, and other RTOs and ISOs. The fifteen states where MISO operates are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, South Dakota, North Dakota, Texas and Wisconsin.

(6) Texas

ERCOT, like PJM, is one of the ten RTOs operating in North America. ERCOT's region occupies the entire Texas interconnection which occupies nearly all of the state of Texas. Unlike the other major NERC interconnections, the high voltage transmission and energy market within the Texas interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation.

(iii) Material Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 104 MW wind powered electrical generating facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The St. Leon Wind Facility entered into a PPA with Manitoba Hydro effective June 17, 2006 under which all electricity produced is sold to Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional five years.

(2) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind powered electrical generating facility located in Lee County, Illinois, 80 km west of Chicago. The Shady Oaks Wind Facility is party to a 20 year power sales contract with the largest electric utility in the state of Illinois, Commonwealth Edison. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. Annual production is subject to contingent curtailment based on certain regulatory constraints of the electricity purchaser. The remaining generation and associated RECs are sold into the market.

(3) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind powered electrical generating facility located near Tyrone, Pennsylvania, 180 km east of Pittsburgh. Sandy Ridge Wind, LLC is party to a long term energy production hedge (the "**Primary Energy Production Hedge**") with respect to the majority of production with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**"), a wholly owned subsidiary of J.P. Morgan, having a term of 10 years beginning January 1, 2013 and is also party to an energy production hedge with another third party for production during 2023. Ancillary services, including capacity and RECs, are sold into the PJM market.

(4) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind powered electrical generating facility located near Minonk, IL, 200 km southwest of Chicago, IL. The Liberty Power Group first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. Minonk Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013 and is also party to an energy production hedge with another third party for production during 2023. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Primary Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the PJM market.

(5) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind powered electrical generating facility located near Graham, Texas, 200 km west of Dallas, Texas. Senate Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under the Primary Energy Production Hedge. RECs are sold into the ERCOT market.

(6) Odell Wind Facility

The Odell Wind Facility is a 200 MW wind powered electrical generating facility located near Windom, Minnesota, 230 km southwest of Minneapolis, Minnesota. Odell Wind Farm LLC has entered into a PPA with an investment grade utility under which all electricity and RECs produced at the facility are sold. The term of the PPA is 20 years.

(7) Deerfield Wind Facility

The Deerfield Wind Facility is a 150 MW wind powered electrical generating facility located in central Michigan, 180 km north of Detroit, Michigan. All energy, capacity, and RECs produced at the facility are sold to a local electric distribution utility pursuant to a 20 year PPA.

(iv) Renewable Energy Credits

RECs are tradeable commodities earned on the basis of 1 REC per MWh of electricity for wind generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. Currently, the Minonk, Sandy Ridge, Senate, and Shady Oaks Wind Facilities each produce and sell RECs through bilateral contracts.

Solar Power Generating Facilities

(i) Production Method

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics or indirectly using concentrated solar power. The Corporation's solar generation facilities, the Cornwall Solar Facility, Bakersfield I Solar Facility and the Bakersfield II Solar Facility, utilize photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this direct current generated power to alternating current through the use of inverters.

(ii) Principal Markets and Distribution Methods

The principal markets for the Liberty Power Group's operational solar facilities are Ontario for the Cornwall Solar Facility and California for the Bakersfield I Solar Facility and the Bakersfield II Solar Facility. The electricity generated by the solar panels is transmitted via electrical collection lines to the facility substation for subsequent delivery to the distribution/transmission system under control of the local distribution company and the ISO.

(1) Ontario

The IESO is an independent, non-profit corporation that is responsible for the real time operation, long term planning and procurement for Ontario's electricity system. The IESO is licensed by the OEB and it reports to the Ontario legislature through Ontario's Ministry of Energy.

(2) California

The CAISO was formed in 1998 following a restructuring of the state electricity markets, and at the recommendation of the FERC. The CAISO operates as a non-profit public corporation responsible for operating the wholesale power system, maintaining the reliability of the grid, and planning for future demands. It is regulated by the FERC.

(iii) Material Facilities

(1) Bakersfield I Solar Facility

The Bakersfield I Solar Facility is a 20 MW ground mounted photovoltaic solar powered electric generating facility that uses single axis trackers to optimize the site's generating efficiency. The site is located near Bakersfield, California, 150 km northwest of Los Angeles. The Bakersfield I Solar Facility achieved commercial operation in April 2015 and has a fixed rate PPA with an investment grade utility with a term of 20 years from commencement of commercial operation.

(iv) Renewable Energy Credits

RECs are tradeable commodities earned on the basis of 1 REC per MWh of electricity for solar generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. These RSP mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year.

Thermal (Cogeneration) Electric Generating Facilities

(i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods.

(ii) Principal Markets and Distribution Methods

The principal markets for the Corporation's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to ISO rules. In addition to grid sales of electricity and power, electricity and thermal energy are also sold to onsite or adjacent third party thermal host facilities for use in production.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the CPUC and FERC. The CAISO administers the wholesale electricity marketplace for the region.

(2) Connecticut

The electricity markets and transmission systems in Connecticut are governed by the ISO-NE. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

(iii) Material Facilities

(1) Sanger Thermal Facility

The Sanger thermal cogeneration facility is a 56 MW natural gas-fired generating facility located in Sanger, California. The facility has a firm capacity and energy PPA with an investment grade utility expiring in 2021. The agreement calls for delivery of 38 MW of firm capacity.

(2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "**Windsor Locks Facility**") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom Corporation pursuant to a ground lease and an energy services agreement. Payments under the energy services agreement are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility. The additional installed capacity at the site is committed to the ISO-NE market in the day ahead energy market, and the capacity and reserve markets as appropriate.

(iv) Renewable Energy Credits

RECs are tradable commodities earned on the basis of 1 REC per 1.33 MWh of electricity for thermal generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. Currently, the Windsor Locks Thermal Facility is qualified for Class III CT RECs for a portion of its production. The facility produces and sells RECs through bilateral contracts.

Business Development

(i) Strategy

The business development group works to identify, develop and construct new power generating facilities, as well as to identify and acquire operating projects that would be complementary and accretive to the Liberty Power Group's existing portfolio. The business development group is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. The Liberty Power Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Liberty Power Group's business development group will begin construction or execute an acquisition agreement.

(ii) Principal Market Environment

The Liberty Power Group believes that future opportunities for power generation projects will continue to develop as new targets are set for renewable and other clean power generation projects.

Within Canada, the market is driven largely by provincial regulations, of which Alberta and Saskatchewan are expected to present the most immediate opportunities for the Corporation. The AESO was commissioned by the Government of Alberta to develop recommendations for the procurement of renewable sources of power that will allow the Province to meet its objective to have 30% of electricity generation by 2030 come from renewable sources. One round of procurements was completed in 2017, with just under 600 MW of contracts awarded. Two additional upcoming rounds of procurements are expected in 2018 and 2019. Additional smaller procurement opportunities are being considered, including a solar procurement process with Alberta Infrastructure.

In Saskatchewan, the vertically-integrated utility SaskPower has set a target of 50% of generation capacity to come from renewables by 2030, which is expected to lead to the development of approximately 1,600 MW of new wind energy generation and 120 MW of utility-scale solar generation. The first competition commenced in 2017, with contracts expected to be awarded in the second quarter of 2018.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity PTCs, a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit, a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. On December 18, 2015, the United States Congress approved a five-year extension to the 30 percent federal investment tax credit for solar energy properties and U.S. 2.3 cents per kilowatt-hour PTC (subject to certain inflation adjustments) for wind facilities. The federal investment tax credit for solar energy will remain at 30 percent through 2019, before it phases down gradually to 10 percent in 2022. The PTC for wind energy was maintained at U.S. 2.3 cents per kilowatt-hour (subject to certain inflation adjustments) for projects on which construction was commenced prior to the end of 2016 before phasing down 20 percent per year and being eliminated at the end of 2019. Federal tax reform passed late in 2017 had no direct impact on these incentive programs. Additionally, other incentives continue to be offered independently for the development of renewable sources of power at the state and local levels. State policies continue to be driven by RPS, which vary between states. As of 2017, 29 states plus Washington D.C. and three territories have adopted binding RPS targets, and eight additional states have taken on voluntary renewable portfolio goals. These targets range between 8.5% and 50% of retail sales to specific entities, to be achieved between 2015 and 2040.

The Liberty Power Group will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

(iii) Current Development or Construction Projects

The Liberty Power Group’s Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and projected investment returns that meet or exceed APUC's investment return criteria.

Project Name	Location	Size (MW)	Commercial Operation	PPA Term (Years from COD)
Projects in Construction				
Amherst Island Wind Project	Ontario	75	2018	20
Great Bay Solar Project	Maryland	75	2018	10
Total Projects in Construction		**150**		
Projects in Development				
Blue Hill Wind Project	Saskatchewan	177	2019/20	25
Val-Éo Wind Project	Québec	24	2018	20
Total Projects in Development		**201**		
Total in Construction and Development		**351**		

(1) Amherst Island Wind Project

The Amherst Island wind project is a 75.0 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario (the "**Amherst Island Wind Project**"). The electricity to be generated by the project is being sold under a 20 year PPA awarded as part of the IESO FIT program. The project has a commercial operation date targeted for the second quarter of 2018.

(2) Great Bay Solar Project

The Great Bay Solar Project is a 75.0 MW solar powered electric generating development project located in Somerset County in southern Maryland. All energy from the project will be sold to the U.S. Government Services Administration pursuant to a 10 year PPA, with a 10 year extension option. All RECs from the project will be retained by the project company and sold into the Maryland market. The project has a commercial operation date targeted for the first quarter of 2018.

(3) Blue Hill Wind Project

The Blue Hill wind project is a 177.0 MW wind powered electric generating development project located in Saskatchewan (the "**Blue Hill Wind Project**"). All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA awarded in 2016. The project is located in the rural municipality of Morse and Lawtonia, Saskatchewan.

The Blue Hill Wind Project will be developed as a single phase installation beginning in early 2019. The project requires final environmental approval and all other necessary permitting.

(4) Val-Éo Wind Project

The Val-Éo wind project is anticipated to be a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec (the "**Val-Éo Wind Project**"). The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Liberty Power Group.

The Liberty Power Group has a 50% equity interest in the project. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $16.0 million.

The project will be developed in two phases. Phase I of the project is expected to be completed in 2018 and is expected to have a total capacity of 24 MW, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA. Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements. All land agreements, construction permits, and authorizations have been obtained for Phase I.

The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

(iv) Future Development Projects – Greenfield Projects

The Corporation continues to pursue new development opportunities in addition to building upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within hydro, solar, wind and natural-gas modes of generation and are located throughout North America.

3.1.3 Specialized Skill and Knowledge

The Liberty Power Group's employees have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of the Liberty Power Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Liberty Power Group in-house. The energy from wind aspect of the business of the Liberty Power Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Liberty Power Group in-house. On a more general level, the production of energy from all facilities requires specialized skill and knowledge, and the Liberty Power Group has employed various personnel who have such skill and knowledge.

3.1.4 Competitive Conditions

Deregulation has increased the demand for privately generated power from a variety of sources including fossil fuels, waste, wind, water, and solar. With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The U.S. Department of Energy has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The Department of Energy believes that as deregulation and open competition evolve, the green power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of power generation does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power has generally been more expensive than traditional forms of generated power. However, in recent years costs have decreased with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, investment tax incentives, RPS, and improved equipment capacity factors, both wind and solar energy have achieved parity with market pricing for electricity in many jurisdictions.

The Liberty Power Group believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.

The Liberty Power Group is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources.

3.1.5 Cycles and Seasonality

(i) Hydroelectric Generating Facilities

The Liberty Power Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies impacting the amount of power that can be generated in a year.

(ii) Wind Power Generating Facilities

The Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

(iii) Solar Power Generating Facilities

The Liberty Power Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Liberty Power Group attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

3.2 Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of rate-regulated utilities throughout the United States that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors, with an approximate regional breakdown as follows:

	West	**Central**	**East**
Natural gas distribution	0	127,000	210,000
Electrical distribution	49,000	172,000	44,000
Water distribution	90,000	28,000	0
Wastewater collection	40,000	2,000	0
Total	179,000	329,000	254,000

The regulated electrical distribution utility systems and related generation assets are located in the states of Arkansas, California, Kansas, Missouri, New Hampshire, and Oklahoma. The regulated natural gas distribution utility systems are located in the states of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri. The regulated water distribution and wastewater collection utility systems are located in the states of Arizona, Arkansas, California, Illinois, Missouri and Texas. The Liberty Utilities Group operates a fleet of regulated electric generation assets with a net capacity of 1,424 MW.

Details with respect to significant Liberty Utilities Group facilities and certain rate and tariff information is set out in Schedules C, D and E.

3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water distribution and wastewater collection systems, electric distribution systems or gas distribution systems, are generally subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure adequate supplies of water, electricity and natural gas together with financial security, transparency in the rate setting process and reasonable prices.

(i) Water Distribution and Wastewater Collection Systems

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a CPCN which imposes an exclusive right and duty to serve in the service territory. A CPCN is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(ii) Electric Distribution Systems

The electricity industry is highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the FPA, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CPCN which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the electric service company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(iii) Natural Gas Distribution Systems

The natural gas industry is regulated at multiple levels - federal, state and sometimes local. Under the U.S. Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

3.2.2 Description of Operations

Water Distribution and Waste Water Collection Systems

(i) Method of Providing Services and Distribution Methods

A water utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility. The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fees and reconnects.

A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation. The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as "effluent", is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facility's operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance is enforced by the State agency to which Federal enforcement powers are delegated.

(ii) Principal Markets and Regulatory Environments

The Liberty Utilities Group's water and wastewater facilities are located in the United States in the states of Arizona, Texas, Illinois, Missouri, Arkansas and California. The water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities generally use a historic or forward looking test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. Rates are approved by the agency to provide the utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(1) Arizona

The ACC is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The ADEQ and the Arizona Department of Water Resources in conjunction with various county agencies (county health units) have primary jurisdiction respecting environmental regulation, water regulation and compliance.

(2) Texas

The Public Utility Commission of Texas is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. This regulatory responsibility was transferred from the Texas Commission on Environmental Quality to the Public Utility Commission of Texas on September 1, 2014. The Texas Commission on Environmental Quality has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

The APSC is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(4) California

The CPUC is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in California for rates and charges. The SWRCB has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the California Safe Drinking Water Act and Title 17 and 22 of the California Code of Regulations (California has primacy) for all water service providers, including those owned and operated by municipalities. The jurisdiction respecting drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The SWRCB is the primary regulator for all discharge permits from drinking water systems in California.

(iii) Material Facilities

(1) Liberty Utilities (Litchfield Park Water & Sewer) Corp. Water & Wastewater Systems

The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, has a service area that includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County. The wastewater system's Palm Valley Water Reclamation Facility has permitted treatment capacity of 5.8 million gallons per day.

(3) Liberty Park Water System

Liberty Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California. Liberty Park Water provides, owns and operates the water system in central Los Angeles. Apple Valley (wholly-owned by Liberty Park Water) owns and operates the water system in Apple Valley, California.

Electric Distribution Systems

(i) Method of Providing Services and Distribution Methods

Electric distribution is the final stage in the delivery system of providing electricity to end users. An electric distribution utility sources and distributes electricity to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge that recovers customer related costs, such as meter readings, and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs.

The electrical distribution utilities located in California, New Hampshire, Missouri, Arkansas, Oklahoma and Kansas are subject to state regulation and rates charged by these utilities must be reviewed and approved by their respective State regulatory authorities.

(ii) Principal Markets and Regulatory Environments

The Liberty Utilities Group operates electrical distribution systems in the states of Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma under a cost-of-service methodology. The utilities use either an historical test year, adjusted pro-forma for known and measurable changes, in the establishment of their rates, or prospective test years based on expenses expected to be incurred in future periods, which is the methodology utilized in California. Pursuant to these methods, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses and administrative and general expenses.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. In the case of the CalPeco Electric System a rate case filing is mandatory every three years.

(1) California

The CPUC regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

The ECAC is an annual filing that sets rates to recover the next year's fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year's fuel and purchased power costs.

Post Test Year Adjustment Mechanism allows the CalPeco Electric System to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

The BRRBA removes the seasonal variations of the revenues and flattens the net revenue (minus fuel, purchased power, and ECAC) to a fixed monthly rate. This eliminates the risk of revenue variations associated with seasonal weather changes.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income programs, all of which are reconciled on an annual basis. Electricity distribution companies are also required to provide electricity commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis.

(3) Missouri

The Corporation's Missouri operations are regulated by the MPSC. The rates and fees for providing electric service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover fuel costs are charged through the Fuel Adjustment Clause.

(4) Arkansas

The APSC is the primary regulatory agency with jurisdiction over the investor owned electric utilities in Arkansas for rates and charges.

(5) Oklahoma

The OCC is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Oklahoma.

(6) Kansas

The KCC is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Kansas.

(iii) Material Facilities

(1) CalPeco Electric System

The CalPeco Electric System provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. CalPeco Electric System's connection base is primarily residential. Its commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores.

The Corporation has entered into a multi-year services agreement with NV Energy commencing January 2016. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, combined with the Luning Facility, satisfy the current California Renewables Portfolio Standard requirement for the five year term of the PPA. The CalPeco Electric System has received approval from CPUC to recover the costs it will incur under this agreement. The CalPeco Electric System has authorization for rate recovery of the costs that the Calpeco Electric System has or will incur to acquire, own, and operate the Luning Facility. On January 31, 2017, the Federal Energy Regulatory Commission authorized transactions between the Luning Facility and the CalPeco Electric System pursuant to the PPA with NV Energy. The system is also subject to FERC regulation.

(2) Granite State Electric System

The Granite State Electric System provides distribution service in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers.

Granite State Electric System is required to provide electric commodity supply for all customers who do not choose to take supply from a competitive supplier ("**Default Service**") in the New England power market, and is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. The Granite State Electric System must file with the NHPUC twice a year to adjust for market prices of power purchased, and is also subject to FERC regulation.

(3) Empire District Electric System

Based in Joplin, Missouri, Empire is a regulated utility providing electric, natural gas and water service in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity. The Empire District Gas Company is a wholly owned subsidiary engaged in the distribution of natural gas in Missouri. The largest urban area served by Empire's gas operations is the city of Sedalia. Empire also operates a fiber optics business. The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the FERC.

Natural Gas Distribution Systems

(i) Method of Providing Services and Distribution Methods

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies. Along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand. Interstate pipelines interconnect with other pipelines and other utility systems, and offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the FERC. Typically, the distribution network operates pipelines (including transmission and distribution pipelines), gate stations, district regulator stations, peak shaving plants and natural gas meters. The gas distribution utilities owned by the Liberty Utilities Group are subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

(ii) Principal Markets & Regulatory Environments

The Liberty Utilities Group owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire. The natural gas utilities use a test year to determine distribution rates for the utility. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses, and administrative and general expenses.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments.

(1) New Hampshire

In New Hampshire, gas utilities are regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(2) Illinois

The Liberty Utilities Group's Illinois operations are regulated by the Illinois Commerce Commission. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(3) Iowa

The Liberty Utilities Group's Iowa operations are regulated by the Iowa Utilities Board. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(4) Missouri

The Liberty Utilities Group's Missouri utility operations are regulated by the MPSC. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(5) Georgia

The Liberty Utilities Group's Georgia operations are regulated by the Georgia Public Service Commission. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(6) Massachusetts

The Liberty Utilities Group's Massachusetts operations are regulated by the Commonwealth of Massachusetts. The MDPU has regulatory jurisdiction over all public utilities and common carriers operating in the Commonwealth, which jurisdiction includes the establishment of approved tariffed rates for the purpose of billing customers. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(iii) Material Facilities

(1) EnergyNorth Gas System

The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, New Hampshire. The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

The EnergyNorth System in New Hampshire recently filed two applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in November 2016 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. A settlement has been reached in this docket and the Corporation is currently awaiting a final decision order. Another application was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham, which has been approved by the NHPUC.

(2) Empire District Gas System

EDG is engaged in the distribution of natural gas in Missouri and serves approximately 43,000 customers. A PGA allows EDG to recover from its customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with EDG's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA allows EDG to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton, GA. The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

The Peach State Gas System’s rates are reviewed and updated annually through a tariff provision called the GRAM. This mechanism allows for the annual review of cost recoveries and the setting of rate base returns with a target of 10.7% return on equity and a range of 10.5% to 10.9%. The Peach State Gas System also files an annual Pipe Replacement Program revision to adjust the rates collected for capital costs incurred to replace cast iron and bare steel pipe in its system.

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The PGA requires a change in rates at least every three months.

(4) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services in six communities located in the southeastern portion of Massachusetts. The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers.

The cost of gas is fully recoverable from customers through the Gas Adjustment Factor (“**GAF**”) when billed to “firm” gas customers included in approved tariffs by the MDPU. The GAF is adjusted twice annually and more frequently under certain circumstances.

(5) Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 190 communities in the states of Illinois, Iowa and Missouri, with a mix of residential, commercial, industrial and transportation customers. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri.

Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the calendar year. Iowa allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the twelve months ended August of each year. Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted annually (in fourth quarter) with allowance to file quarterly.

Natural Gas and Electric Transmission

(i) Method of Providing Services and Distribution Methods

Pipelines offer a variety of services under their FERC tariffs to include firm and interruptible transportation, along with other services to provide commercial markets additional flexibility. Some examples of these types of services would be park and loan, pooling and balancing services. In addition, firm service tariff features would also provide additional features to support secondary market activity to include, but not limited to capacity assignment, capacity releases, segmentation and renewal options.

(ii) Principal Markets & Regulatory Environments

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certifies all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an OATT and publicly post capacity available for transportation, and the agency periodically reviews, under just and reasonable standards, the tariff rates to be charged by the certificate holder. In addition, the FERC prescribes operating and safety standards to be followed along with other federal agencies such as Department of Transportation and the Occupational Safety and Health Administration.

The Empire transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma, and Arkansas and Empire is a member of the SPP which spans an area from the Canadian border in Montana and North Dakota in the north to parts of New Mexico, Texas and Louisiana in the south. The transmission facilities are offered for service under an OATT approved by the FERC and administered by SPP. Service requests are placed in the SPP Open Access Same-Time Information System (OASIS) and is evaluated by SPP for available capacity. SPP determines who is offered available transmission capacity subject to the SPP Tariff and SPP Market Rules and is offered on a non-discriminatory basis. Service requests can be either point-to-point or network service, where network service is used for serving electric load. Empire is subject to four different states regulatory bodies, the SPP regional entity for NERC compliance, SPP Market Rules, and the FERC.

Business Development

The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria.

Granite Bridge

On December 4, 2017, the Liberty Utilities Group announced plans for a new infrastructure project designed to bring additional natural gas supply to New Hampshire’s residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire’s Seacoast region to the central part of the State through an underground pipeline. The proposed Granite Bridge project would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Empire District Electric Wind Projects

On October 31, 2017, the Liberty Utilities Group filed a plan with regulators to expand its wind energy resource. The plan calls for the development of up to 800 MW of new wind generation strategically located in or near its service territory by the end of 2020. As part of this proposed plan, the energy generated by the wind farm is expected to replace the energy currently generated by the Asbury Coal Power Plant. This plan is subject to regulatory approval, which is currently expected to be received by the summer of 2018.

3.2.3 Specialized Skill and Knowledge

The Liberty Utilities Group requires specialized knowledge of the utility systems served including electrical, gas or water and waste water distribution. Upon acquiring a new utility system the Liberty Utilities Group will typically retain the existing employees with such specialized skill and knowledge. In addition, the Liberty Utilities Group will add, when required, additional trained utility personnel at its corporate offices to support the expanded portfolio of utility assets.

3.2.4 Competitive Conditions

The Liberty Utilities Group's businesses have geographic monopolies in their service territories. The Liberty Utilities Group has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Liberty Utilities Group believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on a regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives.

3.2.5 Cycles and Seasonality

(i) Water and Wastewater Systems

Demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

The Corporation attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, the Central Basin and Apple Valley facilities in California, a weather normalization adjustment is applied to customer bills that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(ii) Electricity Systems

The CalPeco Electric System's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. The CalPeco Electric System has implemented a BRRBA rate mechanism that removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a fixed monthly amount. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

The Granite State Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with New England weather. The competitive market for power supply is managed by the ISO-NE. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Granite State Electric System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

The Empire District Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with weather in its service territory. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers and as a result does not have a material financial impact.

(iii) Natural Gas Systems

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather, the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems' demand profiles typically peak in the winter months of January and February and decline in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Liberty Utilities Group attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

3.3 Related Party Transactions

(i) Equity-method investments

The Corporation provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Corporation charged its equity-method investees $6.0 million in 2017 as compared to $3.3 million during the same period in 2016.

(ii) Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of APCI which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2018.

3.4 Principal Revenue Sources

APUC owns, directly or indirectly, interests in renewable generation facilities, thermal generation facilities, electrical distribution utilities, natural gas and propane distribution utilities, and water distribution and wastewater utilities.

The following provides a breakdown of the Corporation’s total revenue by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Total Revenue	
	December 31, 2017	**December 31, 2016**
Non-regulated energy sales	14.3%	22.2%
Utility electricity sales & distribution	50.0%	20.8%
Utility natural gas sales & distribution	24.8%	37.0%
Utility water distribution and wastewater treatment sales & distribution	9.2%	16.6%
Other revenue[1]	1.7%	3.4%

[1] Other revenue includes gas transportation and RECs.

The purchase of electricity and natural gas by the Corporation's electric distribution and natural gas distribution system is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Corporation uses Net Energy Sales for the Liberty Power Group (see *Non-GAAP Financial Measures*) and Net

Utility Sales at the Liberty Utilities Group (see *Non-GAAP Financial Measures*) as a more appropriate measure of the results. Adjusting for the impact of these commodity costs, the following provides a breakdown of the Corporation's Net Energy Sales and Net Utility Sales by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Net Energy Sales/Net Utility Sales	
	December 31, 2017	**December 31, 2016**
Non-regulated energy sales	17.5%	27.6%
Utility electricity sales & distribution	47.8%	13.5%
Utility natural gas sales & distribution	20.9%	33.0%
Utility water distribution and wastewater treatment sales & distribution	11.6%	21.2%
Other revenue[1]	2.2%	4.7%

[1] Other revenue includes gas transportation and RECs.

For the Liberty Power Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Revenue	
	December 31, 2017	**December 31, 2016**
Hydroelectric generation	19.4%	25.0%
Wind generation	57.2%	48.2%
Solar generation	4.7%	4.9%
Thermal generation	12.9%	13.4%
Other revenue[1]	5.8%	8.5%

[1] Other revenue includes RECs.

For the Liberty Utilities Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Revenue	
	December 31, 2017	**December 31, 2016**
Utility electricity sales & distribution	59.0%	27.5%
Utility natural gas sales & distribution	29.3%	48.9%
Utility water distribution and wastewater treatment sales & distribution	10.8%	21.9%
Other revenue[1]	0.9%	1.8%

[1] Other revenue includes gas transportation.

3.5 Environmental Protection

The Corporation's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licenses, permits, standards, policies and legislation. Failure to operate such businesses in strict compliance with these regulatory standards may expose them to citations, claims, clean-up costs, penalties, and loss of operating licenses and permits.

The Corporation has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development, implementation of emergency action plans as related to environmental matters and environmental and compliance departments with responsibility for monitoring the Corporation and its subsidiaries' operations.

Environmental protection requirements did not have a significant financial or operational effect on the Corporation's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2017. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets, such as those described elsewhere in this AIF, are expected to increase the earnings and benefit the competitive position of the Corporation.

The Corporation faces a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities (see "*Enterprise Risk Factors – Risks Relating to Operations*"). Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

3.6 Employees

The Corporation's Executive Management Group consists of eight individuals including the Chief Operating Officers of the Liberty Power Group and the Liberty Utilities Group. As at December 31, 2017, the Corporation employed a total of 2,241 people.

The Liberty Power Group employed a total of 109 employees as at December 31, 2017. All of the employees of the Liberty Power Group are non-unionized.

The Liberty Utilities Group employed a total of 1,854 employees as at December 31, 2017. The Liberty Utilities Group employees are non-unionized with the exception of: 66 employees at the CalPeco Electric System, 41 employees at the Midstates Gas System, 346 employees at The Empire District Electric Company, 183 employees at the EnergyNorth Gas System and Granite State Electric System, and 82 employees at the New England Gas System.

The corporate and shared services groups consisted, as at December 31, 2017, of an additional 194 employees located at the corporate offices in Oakville, Ontario and an additional 76 shared services employees located throughout the United States.

3.7 Foreign Operations

For the twelve months ended December 31, 2017, approximately 100% of the revenue of the Liberty Utilities Group and 70% of the revenue of the Liberty Power Group was generated from operations located in the United States.

3.8 Economic Dependence

The Corporation does not believe it is substantially dependent on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or license or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

3.9 Social or Environmental Policies

The Corporation has formal policies and procedures that support its commitment to corporate responsibility. The Corporation's Code of Business Conduct and Ethics is the foundation of the Corporation's corporate responsibility framework. As a condition of employment, all employees are required to read the Code of Business Conduct and Ethics and apply the code to their work.

Employees are required to complete an annual online test which confirms their compliance with and understanding of the Code of Business Conduct and Ethics. During the course of business, any compliance exceptions are reviewed and managed promptly.

The Corporation's businesses have safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into their respective Safety Mission Statements and Employee manuals.

The Corporation has an Environmental, Health and Safety Group that reports independently to the Corporation's Vice President, People and Culture. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

The Corporation is actively involved in corporate responsibility. Using the Global Reporting Initiative, an international independent standards organization that helps businesses, governments and other organizations understand and communicate their impacts on issues such as climate change, human rights and corruption, the Corporation formally tracks several Global Reporting Initiative indicators. With corporate responsibility as an element of the Corporation's decision making, the Corporation reduces liability for investors, increases morale and engagement of employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders.

Corporate responsibility is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. The Corporation has environmentally supportive programs in place that promote energy efficiency and responsible water usage, help facilitate habitat conservation to minimize impact, monitor greenhouse gas emissions, and promote waste reduction and spill prevention. The economic branch of the Corporation's corporate responsibility efforts incorporates local spending, local hiring, and operational efficiency. The Corporation's commitment to people is demonstrated through its employee training, learning and development programs, organizational improvements, emergency management, health and safety policies, diversity in the workplace, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments, and business partners.

3.10 Credit Ratings

The Corporation maintains the following credit ratings by the rating agencies[1]:

	S&P		DBRS		Moody's	
	2017	2016	2017	2016	2017	2016
APUC - Issuer rating	BBB	BBB	BBB (low)	BBB(low)	-	-
APUC - Preferred Shares	P-3 [3]	P-3 [3]	Pfd-3 (low)	Pfd-3 (low)	-	-
APCo - Issuer rating	BBB	BBB	BBB (low)	BBB (low)	-	-
APCo - Senior unsecured debt	BBB	BBB	BBB (low)	BBB (low)	-	-
Liberty Utilities Co.	BBB	BBB	-	-	-	-
Liberty Utilities Finance GP1 - Issuer rating[2]	-	-	BBB (high)	BBB (high)	-	-
Liberty Utilities Finance GP1 - Senior unsecured notes	-	-	BBB (high)	BBB (high)	-	-
Empire - Issuer rating	BBB	BBB	-	-	Baa1	Baa1
Empire - First mortgage bonds			-	-	A2	A2
Empire - Senior unsecured debt			-	-	Baa1	Baa1
Empire - Commercial paper			-	-	P-2	P-2

1 Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Credit ratings are not a recommendation to buy, sell or hold securities of APUC and do not comment as to market price or suitability for a particular investor. There can be no assurance that a rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn at any time by the rating agency.

2 Issued by Liberty Utilities Finance GP1 and guaranteed by Liberty Utilities Co.

3 P-3 rating is equivalent to a BB rating on S&P's global preferred share rating scale

S&P

S&P rates debt instruments and issuers with ratings ranging from “AAA”, which represent the greatest ability of an obligor to meet its financial commitment, to “D”, which represents an obligor in payment default. A rating of “BBB” by S&P denotes an obligor having adequate capacity to meet its financial commitments. Adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating may be modified by the addition of a plus “+” or minus “-” sign to show relative standing within the major rating categories. The absence of either a plus “+” or minus “-” sign indicates that the rating is in the middle of the category.

According to the S&P rating system, preferred shares rated P-3 are regarded as having significant speculative characteristics. While such securities will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. The ratings from P-1 to P-5 may be modified by “high” and “low” grades which indicate relative standing within the major rating categories.

DBRS

DBRS rates debt instruments and issuers with ratings ranging from “AAA”, which represents debt instruments and issuers of the highest credit quality, to “D”, which represent debt instruments for which a company has not made a scheduled payment of interest or principal or has made it clear it will miss such a payment in the near future. A rating of “BBB” by DBRS denotes an obligor having adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. A DBRS rating may be modified by the addition of a “(high)” or “(low)” to indicate the relative standing within a particular rating category. The absence of either a “(high)” or “(low)” designation indicates that the rating is in the middle of the category.

According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. “High” or “low” grades are used to indicate the relative standing within a rating category. The absence of either a “high” or “low” designation indicates the rating is in the middle of the category.

Moody's

Moody's rates debt instruments and issuers with ratings ranging from “Aaa”, which represent the greatest ability of an obligor to meet its financial commitment, to “C”, which represents an obligor in payment default. A rating of “A” by Moody's denotes obligations judged to be upper-medium grade and are subject to low credit risk, while a rating of “Baa” by Moody's denotes an obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody's rating may be modified by the addition of a numerical modifiers 1, 2, and 3 to show relative standing within the major rating categories.

Short-term obligations of an issuer may carry a rating ranging from Prime-1 or “P-1”, which represents an issuer's superior ability to repay short-term debt obligations, to “P-3”, which represent an issuer's acceptable ability to repay short-term obligations.

4. ENTERPRISE RISK FACTORS

The Corporation is subject to a number of risks and uncertainties. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation’s business could be materially different from what is anticipated. The description of risks below does not include all possible risks.

An enterprise risk management, or ERM, framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of the Corporation’s current objectives, as well as those inherent to strategic alternatives available to the

Corporation. The Corporation's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as the Corporation's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee on a quarterly basis.

Risks are evaluated consistently across the organization using a common risk scoring matrix to assess impact and likelihood. Financial, reputational, and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of the Corporation's strategic and business plans.

The development and execution of risk treatment plans for the organization's top risks are actively monitored by the Executive team. The Corporation's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for key risks. Audit findings are discussed with business owners and reported to the Audit Committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, the Corporate Governance and Risk Committees, and the Board for consideration.

The Corporation's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that the Corporation's risk appetite is thoroughly considered in decision-making across the organization.

4.1 Risk Factors Relating to Operations

The Corporation's operations involve numerous risks that could disrupt or adversely affect its business, results of operations, financial position and cash flows.

The operation of the Corporation's power generation facilities, utility systems and other assets involve a variety of risks customary to the power and utilities sector, including:

- severe weather conditions and natural disasters;
- global climate change;
- environmental contamination/wildlife impacts;
- casualty events such as fires, explosions, security breaches or other occurrences;
- commodity supply and transmission constraints or interruptions;
- workplace and public safety events;
- loss of key personnel;
- labour disputes;
- poor employee performance/workforce effectiveness;
- demand (including seasonality);
- loss of key customers;
- reduction in the price received for goods/services;
- reliance on transmission systems and facilities operated by third parties;
- land use rights/access;
- critical equipment breakdown or failure;
- lower-than-expected levels of efficiency or operational performance;
- wars and terrorist acts;
- commodity price;
- obligations to serve; and
- the Corporation's reliance on subsidiaries.

These and other operating events and conditions could result in service disruptions and may reduce the Corporation's revenues, increase costs, or both, and may materially affect its business, results of operations, financial position, valuation and cash flows, particularly if a situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery.

The Corporation's generation, distribution and transmission utility assets may be negatively impacted by changes in general economic, credit, social and market conditions.

The Corporation's generation, distribution and transmission utility assets are affected by energy demand in the jurisdictions in which they operate, that may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income and housing starts. Significantly reduced energy demand in the Corporation's service territories could reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe prolonged downturn in economic conditions may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the utility services they consume, thereby affecting the aging and collection of the utilities' trade receivables.

Energy conservation, energy efficiency, distributed generation and other factors that reduce energy demand could adversely affect the Corporation's business, financial condition and results of operations.

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of global warming and overall climate change has increased the incentive to increase energy efficiency and reduce energy consumption. In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase as a result of government subsidies, improving economics and changing customer preferences.

Increased adoption of these practices, requirements and technologies could reduce demand for utility-scale electricity generation, which may adversely affect market prices at which the Liberty Power Group can sell wholesale electric power.

Increased adoption of these practices may decrease the pool of customers from whom fixed costs would be recovered. If the Liberty Utilities Group were unable to adjust distribution rates to reflect the reduced energy demand, the Corporation's business, financial condition and results of operations could be adversely affected.

The Corporation is subject to physical and financial risks associated with global climate change.

Global climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, which could adversely affect the Corporation's business, results of operations and cash flows.

The Corporation and its subsidiaries face a number of environmental risks which have the potential to result in significant environmental liabilities.

The Corporation and its subsidiaries face a number of environmental risks that are normal aspects of operating within the power generation and utilities business segments, which have the potential to result in harm to the environment, including wildlife, resulting in significant environmental liabilities and reputational impact. Certain environmental risks associated with the Corporation's operations include uncontrolled natural gas or contaminant releases (or releases above the permitted limits), generation of hazardous materials, failure to maintain compliance with obligations under permits and licenses (such as continuous emissions monitoring, periodic reporting/source testing, and general performance/operating conditions), operations adjustments or liability, and related financial impacts, resulting from wildlife mortality monitoring, emissions including noise and dam safety.

In addition, like other industrial companies, the Corporation's operating subsidiaries generate certain hazardous wastes, which must be managed in accordance with various federal, state and local environmental laws. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

The Corporation's facilities and operations are exposed to effects of natural disasters and other catastrophic events beyond the Corporation's control and such events could result in a material adverse effect.

The Corporation's facilities and operations are exposed to potential interruption and damage, and partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, ice storms, and earthquakes), other seismic activity, equipment failures and the like. There can be no assurance that in the event of an earthquake, hurricane, tornado, tsunami, typhoon, terrorist attack, act of war or other natural, manmade or technical catastrophe, all or some parts of the Corporation's generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event which disrupts the ability of the Corporation's power generation assets to produce or sell power for an extended period, including events which preclude existing customers under power purchase agreements from purchasing electricity, could have a material negative impact on the Corporation's business. The Corporation's infrastructure could be exposed to effects of severe weather conditions, natural and man-made disasters and potentially other catastrophic events. The occurrence of such an event may not release the Corporation from performing its obligations pursuant to power purchase agreements or other agreements with third parties.

Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

Security breaches, criminal activity, terrorist attacks and other disruptions to the Corporation's information technology infrastructure could directly or indirectly interfere with the Corporation's operations, could expose the Corporation or its customers or employees to risk of loss, and could expose the Corporation to liability, regulatory penalties, reputational damage and other harm to its business.

The Corporation relies upon information technology networks and systems to process, transmit and store electronic information, and to manage and support a variety of business processes and activities. The Corporation also uses information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. The Corporation's technology networks and systems collect and store sensitive data, including system operating information, proprietary business information belonging to the Corporation and third parties, as well as personal information belonging to the Corporation's customers and employees.

The Corporation's information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, disruptions during software or hardware upgrades, telecommunication failures, natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of the Corporation's power generation facilities and utility distribution systems; could expose the Corporation, its customers or its employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against the Corporation, damage the Corporation's reputation or otherwise harm the Corporation's business. The Corporation cannot accurately assess the probability that a security breach may occur or accurately quantify the potential impact of such an event. The Corporation can provide no assurance that it will identify and remedy all security or system vulnerabilities or that unauthorized access or errors will be identified and remedied.

The loss of key personnel, the inability to hire and retain qualified employees, and labour disruptions could adversely affect the Corporation's business, financial position and results of operations.

The Corporation's operations depend on the continued efforts of its employees. Retaining key employees and maintaining the ability to attract new employees are important to the Corporation's operational and financial performance. The Corporation cannot guarantee that any member of its management or any one of its key employees will continue to serve in any capacity for any particular period of time.

Certain events or conditions, such as an aging workforce, epidemic or pandemic, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges the Corporation might face as a result of such risks include a lack of resources, losses to its knowledge base and the time required to develop new workers' skills. In any such case, costs, including costs for contractors to replace employees, productivity costs and safety costs may rise. If the Corporation is unable to successfully attract and retain an appropriately qualified workforce, its financial position or results of operations could be negatively affected.

The maintenance of a productive and efficient labour environment without disruptions cannot be assured. In the event of a strike, work stoppage or other form of labour disruption, the Corporation would be responsible for procuring replacement labour and could experience disruptions in its operations and incur additional expense.

The Corporation's revenues and results of operations are affected by seasonal fluctuations and year to year variability in weather conditions and natural resource availability.

The Corporation is subject to risks associated with seasonal fluctuations and year to year variability in weather conditions and natural resource availability, which affect the quantity of electric power generated and sold by the Liberty Power Group, the availability of water to be distributed by the Liberty Utilities Group and the demand for the utility services of the Liberty Utilities Group.

Demand for energy sold to retail customers in the maritime region is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served is located in a "winter peaking" region.

The Liberty Utilities Group's water distribution operations depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of these utilities.

Demand for water, electricity and natural gas from the Liberty Utilities Group's utility distribution systems is affected by weather conditions and temperature. Demand for water may decrease if there is above normal rainfall or rainfall is more frequent than normal, or if government restrictions are imposed on water usage during drought conditions. Demand for electricity and natural gas are also subject to significant seasonal variation, year-to-year variations and changes in weather patterns.

Please see "*Description of the Business – Liberty Power Group – Cycles and Seasonality*" and "*Description of the Business – Liberty Utilities Group – Cycles and Seasonality*" for a detailed description and discussion of this risk.

The Corporation historically has, and may in the future, enter into long-term power purchase contracts and derivative contracts to reduce the risk of fluctuations in electricity prices, which contracts could give rise to performance and financial risks and could result in significant costs to the Corporation.

The Liberty Power Group sells a significant portion of the energy (and renewable energy credits) it generates under long-term power purchase agreements. To the extent a generating asset is not fully covered by a power purchase contract, the Liberty Power Group may enter into financial or physical power hedges to reduce the risk from fluctuations in market price. For instance, several of the Liberty Power Group's wind energy production facilities are subject to long-term energy price hedges for a portion of their expected energy production. The Corporation may incur significant costs in establishing or terminating hedging arrangements or may be unable to benefit from favorable changes in market price as a result of these hedges.

In addition, the Corporation may not be able to generate power in the amounts or at the times required by the applicable hedge contract, due to the variable nature of the natural resource (for renewable power generation) or due to transmission grid curtailments, mechanical failures or other reasons. Because of this risk, the Corporation typically does not hedge the full expected production of a particular facility, which leaves a portion of expected production subject to market price risk. In addition, production shortfalls force the Liberty Power Group to purchase power in the merchant market at prevailing rates to settle against the applicable hedge contract. Such factors could materially and adversely affect the Corporation's results of operations and cash flows, depending on both the amount of shortfall and the market price of electricity at the time of the shortfall.

Changes in technology and regulatory policies may lower the value of electric utility facilities.

The Corporation primarily generates electricity at large central facilities and delivers that electricity to customers using its transmission and distribution facilities. This method results in economies of scale and generally lower costs than newer technologies, such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. The ability to maintain relatively low-cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers are significant determinants of the Corporation's competitiveness. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost central generating plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output and could adversely affect the Corporation's financial condition, results of operations and cash flows, which could also result in an impairment of certain long-lived assets.

Liberty Power Group's facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.

A substantial portion of the Liberty Power Group's power generation facilities depend on electric transmission systems and related facilities owned and operated by third parties to deliver the electricity the Liberty Power Group generates to delivery points where ownership changes and the Corporation is paid. These grids operate with both regulatory and physical constraints which in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which the Liberty Power Group's power generation facilities are physically disconnected from the power grid, or their production curtailed, for short periods of time. Most of the Corporation's electricity sales contracts do not provide for payments to be made if electricity is not delivered.

The power generation facilities of the Liberty Power Group may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which its power generation facilities are connected. In the future, these power generation facilities may not be able to secure access to interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate power purchase agreements or to construct new projects. Any such increased costs and delays could delay the commercial operation dates of Liberty Power Group's new projects and negatively impact the Corporation's revenues and financial condition.

The Corporation's subsidiaries do not own all of the land on which their projects are located and their use and enjoyment of real property rights for their projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to the Corporation's subsidiaries' projects, which could have a material adverse effect on their business, results of operations, financial condition and cash flows.

The Corporation's subsidiaries do not own all of the land on which their projects are located. Such projects generally are, and future projects may be, located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of the rights under such easements, leases or rights of way held by the Corporation's operating subsidiaries may be subject to the rights of these third parties, and the rights of the Corporation's operating subsidiaries to use the land on which their projects are or will be located and their projects' rights to such easements, leases and rights of way could be lost or curtailed. Any such loss or curtailment of the rights of the Corporation's operating subsidiaries to use the land on which their projects are or will be located could have a material adverse effect on their business, results of operations, financial condition and cash flows.

The Corporation may experience critical equipment breakdown or failure, which could have a material adverse effect on the Corporation's financial condition, results of operations, liquidity, reputation and ability to make distributions.

The Corporation's facilities are subject to the risk of critical equipment breakdown or failure and lower-than-expected levels of efficiency or operational performance due to the deterioration of assets from use or age, latent defect and design or operator error, among other things. These and other operating events and conditions could result in service disruptions and, to the extent that a facility's equipment requires longer than forecasted down times for maintenance and repair, or suffers disruptions of power generation, distribution or transmission for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected. In addition, a portion of the Corporation's infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to the business of the Corporation. Continued hostilities or sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on the Corporation in particular, cannot be known. Increased security measures taken by the Corporation as a precaution against possible terrorist attacks have resulted in increased costs to the business of the Corporation. Uncertainty surrounding continued hostilities or sustained military campaigns may affect operations of the Corporation in unpredictable ways, including disruptions of supplies and markets for products of the Corporation, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The Corporation cannot predict the impact that a terrorist attack may have on the energy industry in general. The Corporation's facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to the Corporation's generation, transmission and distribution systems or to the electrical grid in general, and could result in a decline in the general economy and have a material adverse effect on the Corporation.

The Corporation's financial performance may be adversely affected by fluctuations in commodity prices.

Market prices for power, generation capacity, ancillary services and natural gas are unpredictable and tend to fluctuate substantially, which may affect the Corporation's operating results. With respect to the Liberty Utilities Group, commodity price exposure is primarily limited to the cost of electricity and natural gas. Although the Liberty Utilities Group's utility rates and tariffs are generally designed to allow recovery of commodity costs, timing differences and other factors, which may be exacerbated by fluctuating prices, may result in less than full recovery.

Cash flow deferrals related to energy commodities can be significant.

The Corporation is permitted to collect from customers only amounts approved by regulatory commissions. However, the Corporation's costs to provide energy service can be much higher or lower than the amounts currently billed to customers. The Corporation is permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect the Corporation's results of operations.

Even if the regulators ultimately allow the Corporation to recover deferred power and natural gas costs, the Corporation's operating cash flows can be negatively affected until these costs are recovered from customers.

The Liberty Utilities Group is obligated to serve utility customers within its certificated service territories, which may require that the Corporation make capital expenditures and incur indebtedness to expand service to new customers.

The Liberty Utilities Group may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, the Liberty Utilities Group may be required to solicit additional capital or incur additional borrowings to finance these future construction obligations.

As a holding company, the Corporation does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments.

The Corporation is a holding company with no significant operations of its own, and the Corporation's primary assets are shares or other ownership interests of its subsidiaries. The Corporation's subsidiaries are separate and distinct legal entities and may have no obligation to pay any amounts to the Corporation, whether through dividends, loans or other means. The ability of the Corporation's subsidiaries to pay dividends or make distributions to the Corporation depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future secured debt and other debt or equity securities. Further, the amount and payment of dividends from any subsidiary is at the discretion of such subsidiary's board of directors, which may reduce or cease payment of dividends at any time. In addition, there may be changes to tax regulation affecting the repatriation of dividends from other countries, which may negatively affect us.

The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to higher insurance premiums, and the Corporation's ability to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

The Corporation maintains insurance coverage for certain exposures, but this coverage is limited and the Corporation is generally not fully insured against all significant losses. Such insurance may not continue to be offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the Corporation's assets or operations. The Corporation's ability to obtain and maintain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

If the Corporation were to incur a serious uninsured loss or a loss significantly exceeding the limits of their insurance policies, the results could have a material adverse effect on the Corporation's business, results of operations, financial condition and cash flows. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the Liberty Utilities Group, the Corporation may make an application to an applicable regulatory authority for the recovery of these costs through customer rates to offset any loss. However, the Corporation cannot provide assurance that the regulatory authorities would approve any such application in whole or in part. This potential recovery mechanism is not available to Liberty Power Group.

4.2 Risk Factors Relating to Financing and Financial Reporting

A downgrade in the Corporation's credit rating or the credit ratings of its subsidiaries could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations.

The Corporation has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing affiliate of Liberty Utilities Co., has a BBB (high) issuer rating from DBRS. The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. The lower the rating, the higher the interest cost of the securities when they are sold. See "*Description of the Business – Credit Ratings*".

There can be no assurance that any of the Corporation's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. A downgrade in the Corporation's or Liberty Utilities Finance GP1's credit ratings would result in an increase in the Corporation's borrowing costs under its bank credit facilities and future issuances of long term debt securities. If any of these ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), the Corporation's ability to issue short-term debt or other securities, or to market those securities, would be impaired or become more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations.

Financial market disruptions or other factors could increase financing costs or limit access to credit and capital markets, which could adversely affect the Corporation's ability to refinance existing indebtedness on favorable terms, execute its acquisition and investment strategy, and finance its other activities upon favorable terms.

As of December 31, 2017, the Corporation had substantial indebtedness. Management of the Corporation believes, based on its current expectations as to the Corporation's future performance, that the cash flow from operations, funds available under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity for at least the next twelve months. However, the Corporation's expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations will depend on regulatory, market and other conditions that are beyond the Corporation's control. As a result, there can be no assurance that management's expectations as to future performance will be realized.

The Corporation's ability to raise additional debt or equity, on favorable terms or at all, may be adversely affected by any adverse financial and operational performance or by financial market disruptions or other factors outside the Corporation's control.

In addition, the Corporation may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the Corporation's leverage could, among other things, limit the Corporation's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation's flexibility and discretion to operate its business; limit the Corporation's ability to declare dividends; require the Corporation to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporation's existing credit ratings; expose the Corporation to increased interest expense on borrowings at variable rates; limit the Corporation's ability to adjust to changing market conditions; place the Corporation at a competitive disadvantage compared to its competitors that have less debt; make the Corporation vulnerable to any downturn in general economic conditions; and render the Corporation unable to make expenditures that are important to its future growth strategies.

The Corporation will need to refinance its existing consolidated indebtedness over time. There can be no assurance that the Corporation will be successful in refinancing its indebtedness when necessary or that additional financing will be obtained when needed, on commercially reasonable terms or at all. In the event that the Corporation cannot refinance indebtedness or raise additional indebtedness, or if the Corporation cannot refinance its indebtedness or raise additional indebtedness on terms that are not less favourable than the current terms, the Corporation's cash flows and ability to declare dividends may be adversely affected.

The Corporation's ability to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the Corporation's financial performance, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and capital expenditure requirements. In addition, the Corporation's ability to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Corporation and permit acceleration of the relevant indebtedness. There can be no assurance that, if such indebtedness were to be accelerated, the Corporation's assets would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay its outstanding indebtedness or to fund the Corporation's other liquidity needs.

Sustained increases in interest rates could negatively affect the Corporation's financing costs, ability to access capital and ability to continue successfully implementing its business strategy.

The Corporation is exposed to interest rate risk from certain outstanding variable interest indebtedness. As a result, increases in interest rates could materially increase the Corporation's financing costs and adversely affect its results of operations, cash flows, borrowing capacity and ability to implement its business strategy.

Currency exchange rate fluctuations may affect the Corporation's financial results and increase certain financing risks.

Currency fluctuations may affect the cash flows the Corporation realizes from its consolidated operations because a significant portion of the Corporation's revenues are generated in U.S. dollars. Although the Corporation may enter into derivative contracts to hedge currency exchange rate exposure, the Corporation typically does not hedge its full exposure. If the Corporation does enter into currency hedges and exchange rates move in a favourable direction, such currency hedges may reduce or eliminate the Corporation's realization of the benefit of favorable exchange rate movement. In addition, any currency hedging transactions will be subject to risks that the applicable counterparty may prove unable or unwilling to perform their obligations under the contracts, as a result of which the Corporation would lose some or all of the anticipated benefits of such hedging transactions.

The Corporation's existing credit facilities contain, and agreements that the Corporation may enter into in the future may contain, covenants that could restrict its financial flexibility.

The Corporation's existing credit facilities, and the credit facilities of its subsidiaries, contain covenants imposing certain requirements on the Corporation's business including covenants regarding the ratio of indebtedness to total capitalization. Furthermore, the Corporation's subsidiaries periodically issue long-term debt, historically consisting of both secured and unsecured indebtedness. These third-party debt agreements also contain covenants, including covenants regarding the ratio of indebtedness to total capitalization. These requirements may limit the Corporation's ability to take advantage of potential business opportunities as they arise and may adversely affect the Corporation's conduct and the current business of its operating subsidiaries, including restricting the ability to finance future operations and capital needs and limiting the subsidiaries' ability to engage in other business activities. Other covenants place or could place restrictions on the Corporation's ability and the ability of its operating subsidiaries to, among other things, incur additional debt, create liens, and sell or transfer assets.

Agreements the Corporation enters into in the future may also have similar or more restrictive covenants, especially if the general credit market deteriorates. A breach of any covenant in the existing credit facilities or the agreements governing the Corporation's other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration of payment of the underlying obligations or may trigger acceleration of payment if not remedied within a specified period. Events of default under one agreement may trigger events of default under other agreements, although the Corporation's regulated utilities are not subject to the risk of default of affiliates. Should payments become accelerated as the result of an event of default, the principal and interest on such borrowing would become due and payable immediately. If that should occur, the Corporation may not be able to make all of the required payments or borrow sufficient funds to refinance the accelerated debt obligations. Even if new financing is then available, it may not be on terms that are acceptable to the Corporation.

A significant portion of the Corporation's debt will mature over the next five years and will need to be paid or refinanced, and changes to the debt and equity markets could adversely affect the Corporation's business.

A significant portion of the Corporation's debt is set to mature in the next five years, including its revolving credit facility. The Corporation may not be able to refinance its maturing debt on commercially reasonable terms, or at all, depending on numerous factors, including its financial condition and prospects at the time and the then current state of the banking and capital markets in Canada and the United States.

Challenges to the Corporation's tax positions, and changes in applicable tax laws, could materially and adversely affect the return to the Corporation's shareholders.

The Corporation is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect the Corporation's results from operations, return to shareholders and cash flow.

The Corporation cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Corporation, including with respect to claimed expenses and the cost amount of the Corporation's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or we are unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that we are committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

The Corporation is subject to funding risks associated with defined benefit pension and OPEB plans.

Certain utility businesses acquired by the Corporation maintain defined benefit pension plans covering substantially all of the employees of the acquired business, and other post-employment benefit ("**OPEB**") plans for eligible retired employees, including retiree health care and life insurance benefits. The Corporation also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit.

Future contributions to the Corporation's plans are impacted by a number of variables, including the investment performance of the plans' assets and the discount rate used to value the liabilities of the plans. If capital market returns are below assumed levels, or if discount rates decrease, the Corporation could be required to make contributions to its plans in excess of those currently expected, which would adversely affect the Corporation's cash flows.

The Corporation is subject to credit risk of customers and other counterparties.

The Corporation is subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Corporation, including paying amounts that they owe to the Corporation. This credit risk exists with respect to utility customers, as well as counterparties to long term power purchase contracts, supply agreements and derivative financial instruments.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Corporation. Losses from a utility customer may not be offset by bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement is unable to perform, the Liberty Power Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

The Corporation makes certain assumptions, judgments and estimates that affect amounts reported in its consolidated financial statements with respect to potential asset retirement obligations, which, if not accurate, may adversely affect its financial results.

The Corporation and its subsidiaries conduct periodic reviews of potential asset retirement obligations that may require recognition in the Corporation's financial statements. As part of this process, the Corporation and its subsidiaries consider requirements outlined in applicable operating permits, leases and other agreements, the probability of related agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors in evaluating if such obligations exist and in estimating the fair value of such obligations. Inaccuracies in these estimates could result in the Corporation incurring significant expenses related to retirement obligations and adversely affect the Corporation's financial results.

The Corporation's asset retirement obligations mainly relate to legal requirements for: (i) removal of wind, solar and thermal facilities upon termination of land leases; (ii) cutting (disconnecting from the distribution system), purging (cleaning of natural gas and PCB contaminants) and capping gas mains within the gas distribution and transmission system when mains are retired in place, or disposing of sections of gas main when removed from the pipeline system; (iii) cleaning and removing storage tanks containing waste oil and other waste contaminants; and (iv) removing asbestos upon major renovation or demolition of structures and facilities.

4.3 Risk Factors Relating to Regulatory Environment

The profitability of the Corporation's businesses depends in part on regulatory climates in the jurisdictions in which it operates, and the failure to maintain required regulatory authorizations would materially and adversely affect the Corporation.

The utility commissions in the states in which the Liberty Utilities Group operates regulate many aspects of its utility operations, including the rates that the Liberty Utilities Group can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and the utility's ability to recover the costs that it incurs, including capital expenditures and fuel and purchased power costs. In addition, the electrical transmission system owned by the Liberty Power Group, which is used to connect the Tinker Hydro Facility to the New Brunswick transmission network, is also subject to regulation by the New Brunswick Energy and Utilities Board.

A fundamental risk faced by any regulated utility is the disallowance by the utility's regulator of costs requested to be placed into the utility's revenue requirement. In addition, the time between the incurrence of costs and the granting of the rates to recover those costs by state or provincial regulatory agencies – known as "regulatory lag" – can adversely affect profitability. If the Corporation is unable to recover increased costs of operations or its investments in new facilities, or in the event of significant regulatory lag, the Corporation's results of operations could be adversely affected.

In addition, there is a risk that the utility's regulator will not approve the transmission and distribution revenue requirements requested in outstanding or future applications for rates or will, on its own initiative, seek to reduce the existing revenue requirements. Rate applications for revenue requirements are subject to the utility regulator's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the utility regulators will permit the Corporation to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Liberty Utilities Group's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Corporation. In addition, there is no assurance that the Corporation will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

In the case of some of the Corporation's hydroelectric generating facilities, water rights are owned by governments that reserve the right to control water levels, which may affect revenue, while in the United States, hydroelectric generating facilities are required to be licensed or have valid exemptions from FERC. The failure to obtain all necessary licenses or permits for such facilities, including renewals thereof or modifications thereto, may result in an inability to operate the facility and could adversely affect cash generated from operating activities.

FERC has jurisdiction over wholesale rates for all electric energy sold by the Liberty Power Group in the United States. The Liberty Power Group's facilities in the United States are required to meet the requirements of a "qualified facility" or an "exempt wholesale generator" and, subject to certain exceptions, to obtain and maintain authority from FERC to sell power at market-based rates. The failure of the Liberty Power Group to maintain market-based rate authorization for certain facilities that currently have it would constitute a default under the facility's power purchase agreement and any project financing for such facility, and could materially and adversely affect the Corporation.

The operations of each of the Corporation's business units are also subject to a variety of federal, provincial and state environmental and other regulatory bodies, the requirements and regulations of which affect the operations of and costs incurred by the Corporation. In addition, changes in regulations or the imposition of additional regulations also could have a material adverse effect on the Corporation's results of operations.

The Corporation's operations are subject to numerous health and safety laws and regulations.

The operation of the Corporation's facilities requires adherence to safety standards imposed by regulatory bodies. These laws and regulations require the Corporation to obtain approvals and maintain permits, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the citing, construction, operation and decommissioning of wind energy projects. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions.

Health and safety laws, regulations and permit requirements may change or become more stringent. Any such changes could require us to incur materially higher costs than the Corporation has incurred to date. The Corporation's costs of complying with current and future health and safety laws, regulations and permit requirements, and any liabilities, fines or other sanctions resulting from violations of them, could adversely affect its business, financial condition and results of operations.

The Corporation is subject to numerous environmental laws, regulations and other standards that may result in capital expenditures, increased operating costs and various liabilities.

The Corporation is subject to extensive federal, state, provincial and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on the Corporation's results of operations and financial position. In addition, new environmental laws and regulations and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted, which may substantially increase the Corporation's future environmental expenditures. Although the Liberty Utilities Group has historically recovered such costs through regulated customer rates, there can be no assurance that the Liberty Utilities Group will recover all or any part of such increased costs in future rate cases. The Liberty Power Group generally has no right to recover such costs from customers. The incurrence of additional material environmental costs which are not recovered in utility rates may result in a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation may pursue growth opportunities in new markets that are subject to foreign laws or regulation that are more onerous than the laws and regulations to which it is currently subject.

The Corporation may pursue growth opportunities in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with the Corporation's contractual relationships in such countries, as are afforded to the Corporation currently, which may adversely affect the Corporation's ability to receive revenues or enforce its rights in connection with any operations in such jurisdictions. In addition, the laws and regulations of some countries may limit the Corporation's ability to hold a majority interest in certain growth projects, thus limiting the Corporation's ability to control the operations of such projects. Any existing or new operations may also be subject to significant political, economic and financial risks, which vary by country, and may include: (i) changes in government policies or personnel; (ii) changes in general economic conditions; (iii) restrictions on currency transfer or convertibility; (iv) changes in labour relations; (v) political instability and civil unrest; (vi) regulatory or other changes in the local electricity market; and (vii) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

4.4 Risk Factors Relating to Strategic Planning and Execution

The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. There is no certainty that the Corporation will be successful in pursuing this growth strategy in the future. There can be no assurance that the Corporation will be able to identify attractive acquisition or development candidates in the future or that it will be able to realize growth opportunities that increase the amount of cash available for distribution. The Corporation may also face significant competition for growth opportunities and, to the extent that any opportunities are identified, may be unable to effect such growth opportunities due to a lack of necessary capital resources. Risks related to capital projects include schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, however, there is no assurance that any project cost overruns would be approved for recovery in customer rates.

Any growth opportunity could involve potential risks, including an increase in indebtedness, the potential disruption to the Corporation's ongoing business, the diversion of management's attention from other business concerns and the possibility that the Corporation will incur more costs than originally anticipated or, in the case of acquisitions, more than the acquired company or interest is worth. In addition, funding requirements associated with the growth opportunity, including any acquisition, development or integration costs, may reduce the funds available to pay dividends.

The Corporation's capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower than anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

The Corporation's development and construction activities are subject to material risks, including expenditures for projects that may prove not to be viable, construction cost overruns and delays, inaccurate estimates of expected energy output or other factors, and failure to satisfy tax incentive requirements or to meet third-party financing requirements.

The Corporation actively engages in the development and construction of new power generation facilities, and currently has a pipeline of projects in development or construction, consisting mainly of solar and wind power generation projects, as well as the development and construction of transmission and distribution assets. In addition, each of the Corporation's business segments may occasionally undertake construction activities as part of normal course maintenance activities.

Significant costs must be incurred to determine the technical feasibility of a project, obtain necessary regulatory approvals and permits, obtain site control and interconnection rights and negotiate revenue contracts for the facility before the viability of the project can be determined. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked, or the failure of a project to proceed and the resultant loss of amounts invested or expenses already incurred.

Once under construction, material delays or cost overruns could be incurred as a result of vendor or contractor performance, technical issues with the interconnection utility, disputes with landowners or other parties, severe weather and other causes.

The Corporation's assessment of the feasibility, revenues and profitability of a renewable power generation facility depends upon estimates regarding the strength and consistency of the applicable natural resource (such as wind, solar radiance or hydrology) and other factors, such as assessments of the facility's potential impact on wildlife. If weather patterns change or actual data proves to be materially different than estimates, the amount of electricity to be generated by the facility and resulting revenues and profitability may differ significantly from expected amounts.

For certain of its development projects, the Liberty Power Group relies on financing from third party tax equity investors, the participation of which depends upon qualification of the project for U.S. tax incentives and satisfaction of the investors' investment criteria. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities would be adversely impacted.

The Liberty Power Group depends on certain key customers for a significant portion of its revenues. The loss of any key customer or the failure to secure new power purchase agreements or to renew existing power purchase agreements could increase market price risk with respect to the sale of generated energy and renewable energy credits.

A substantial portion of the output of the Liberty Power Group's power generation facilities is sold under long-term power purchase agreements, under which a single purchaser is obligated to purchase all of the output of the applicable facility and (in most cases) associated renewable energy credits. The termination or expiry of any such power purchase agreement, unless replaced or renewed on equally favorable terms, would adversely affect the Corporation's results of operations and cash flows and increase the Corporation's exposure to risks of price fluctuations in the wholesale power market.

Securing new power purchase agreements is a risk factor in light of the competitive environment in which the Corporation operates. The Corporation expects the Liberty Power Group to continue to enter into power purchase agreements for the sale of its power, which power purchase agreements are mainly obtained through participation in competitive requests for proposals processes. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There can be no assurance that the Corporation will be selected as power supplier following any particular request for proposals in the future or that existing power purchase agreements will be renewed or will be renewed on favourable terms and conditions upon the expiry of their respective terms.

The Corporation may fail to complete planned acquisitions, which may result in a loss of expected benefits from such acquisitions or may generate significant liabilities.

Acquisitions of complementary businesses and technologies are a part of the Corporation's overall business strategy. Because of the regulated nature of the business sectors in which the Corporation operates, nearly all acquisitions by the Corporation are subject to various regulatory approvals and, consequently, to the risks that such approvals may not be timely obtained or may impose unfavorable conditions that could impair the ability to complete the acquisition or impose adverse conditions on the Corporation following the acquisition.

In addition, the Corporation may enter into acquisition agreements under which the Corporation's obligations are not contingent upon availability of financing, in which case the Corporation could incur higher than expected financing costs or, if such financing cannot be obtained, significant liability to the seller.

Failure to complete an acquisition may decrease investor confidence. In addition, the terms of an acquisition agreement may impose liability on the Corporation for failing to complete the acquisition, which in some cases may include liability where the reasons for failure to complete the acquisition are not entirely within the Corporation's control.

The Corporation may fail to realize the intended benefits of completed acquisitions or may incur unexpected costs or liabilities as a result of completed acquisitions.

The Corporation may not effectively integrate the services, technologies, key personnel or businesses of acquired companies or may not obtain anticipated operating benefits or synergies from completed transactions will not be realized. In addition, the Corporation may incur unexpected costs or liabilities in connection with the closing or integration of any acquisition.

The success of an acquisition may depend on retention of the workforce or key employees of the acquired business. The Corporation may not be successful in retaining such workforce or key employees or in retaining them at anticipated costs.

In addition, the Corporation may be subject to unexpected liabilities, despite any due diligence investigation of an acquired business or any contractual remedies the Corporation may have against the sellers. Detailed information regarding an acquired business is generally available only from the seller, and contractual remedies are typically subject to negotiated limitations. In addition, in cases in which the target company is publicly traded and its shares are widely held, the Corporation is likely not to have recourse following the completion of the acquisition for misrepresentations made to the Corporation in connection with the acquisition.

The Corporation's anticipated investment in Atlantica will be subject to the risk that Atlantica may make decisions with which the Corporation does not agree or take risks or otherwise act in a manner that does not serve the Corporation's interests.

Pursuant to the anticipated Atlantica investment, the Corporation will be investing in equity securities of Atlantica, a company that the Corporation does not control. In addition, subject to certain conditions and limited exceptions, the Corporation has agreed not to increase its interest in Atlantica above 41.5%. As a result, this anticipated investment will be subject to a risk that Atlantica may make business, financial or management decisions with which the Corporation does not agree, or that Atlantica's other stockholders or management of Atlantica may take risks or otherwise act in a manner that does not serve the Corporation's interests. If any of the foregoing were to occur, the value of the Corporation's investment could decrease and the Corporation's financial condition, results of operations and cash flow could be adversely affected.

Dividends declared and paid by Atlantica are made at the discretion of Atlantica's board of directors. The Corporation will not control the board of directors of Atlantica. Therefore, there can be no assurance that dividends will continue to be paid on Atlantica's ordinary shares, will continue to be paid at the same rate as is currently being paid or will be paid at any specified target rate.

Demand in the capital markets for Atlantica's ordinary shares can vary over time for numerous reasons outside of the Corporation's control, including performance of the Atlantica business and changes in the prospects of Atlantica. Consequently, it may be difficult for the Corporation to dispose of its anticipated interest in Atlantica at favourable times or prices.

The Corporation's anticipated investment in Atlantica will expose it to certain risks that are particular to Atlantica's business and the markets in which Atlantica operates.

Atlantica owns, manages and acquires renewable energy, conventional power, electric transmission lines and water assets in jurisdictions where the Corporation does not currently operate, including Mexico, Peru, Chile, Brazil, Uruguay, Spain, Algeria and South Africa. The Corporation, through its anticipated investment in Atlantica, will be indirectly exposed to certain risks that are particular to Atlantica's business and the markets in which it operates, including, but not limited to, risks related to: conditions in the global economy; changes to national and international laws, political, social and macroeconomic risks relating to the new jurisdictions, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery laws and substantial penalties and reputational damage from any non-compliance therewith; Atlantica's ability to identify and/or consummate future acquisitions on favourable terms or at all; Atlantica's inability to replace, on similar or commercially favourable terms, expiring or terminated offtake agreements; reputational risk, including with respect to the reputation of Abengoa; termination or revocation of Atlantica's concession agreements or power purchase agreements; Abengoa's ability to meet its obligations under its agreements with Atlantica; and various other factors. These risks could affect the profitability and growth of Atlantica's business, and ultimately the profitability of the Corporation's anticipated investment therein.

The Liberty Utilities Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions.

The Liberty Utilities Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require that just and fair compensation be paid to the Liberty Utilities Group, and the Liberty Utilities Group believes that such compensation generally would reflect fair market value for any assets that are taken. However, the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and, therefore, there can be no assurance that the value received for those assets would reflect the value the Corporation attributes to such assets, that the value received would be above book value or that the Corporation would not recognize a loss.

Increased external stakeholder activism could have an adverse effect on the Corporation's ability to execute its capital programs.

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility return on equity and executive compensation. In addition, public opposition to larger infrastructure projects in certain areas is becoming increasingly common, which can challenge a utility's ability to execute its capital programs. The social acceptance by external stakeholders, including, in some cases, First Nations and other aboriginal peoples, local communities and other interest groups may be critical to the Corporation's ability to find and develop new sites suitable for viable renewable energy projects. Failure to obtain proper social acceptance for a project may prevent the development and construction of a project and lead to the loss of all investments made in the development and the write-off of such prospective project. Failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs, and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

The Corporation will not have sole control over the projects that invests in with its joint venture partner, Abengoa, or over the revenues and certain decisions associated with those projects, which may limit the Corporation's flexibility with respect to these projects.

Despite having a 50% equity stake in AAGES, the joint venture involves risks, including, among others, a risk that Abengoa:

- may have economic or business interests or goals that are inconsistent with the Corporation's economic or business interests or goals;
- may take actions contrary to the Corporation's policies or objectives with respect to the Corporation's investments;
- may contravene applicable anti-bribery laws that carry substantial penalties for non-compliance and could cause reputational damage and a material adverse effect on the business, financial position and results of operations of AAGES and the Corporation;
- may have to give its consent with respect to certain major decisions;
- may become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- may become engaged in a dispute with the Corporation that might affect the Corporation's ability to develop a project; or
- may have competing interests in the Corporation's markets that could create conflict of interest issues.

Further, the Corporation will not have sole control of certain major decisions relating to the projects that the Corporation pursues through AAGES, including, among others, decisions relating to funding and transactions with affiliates.

The Corporation may sell businesses or assets, which may be sold at a loss and which, regardless of the sales price, may reduce total revenues and net income.

The Corporation may from time to time dispose of businesses or assets that the Corporation no longer views as being strategic to the Corporation's continuing operations. Such disposals may result in recognition of a loss upon such a sale. In addition, as a result of divestitures, the Corporation's revenues and net income may decrease.

The price of the Corporation's Common Shares may be volatile and the value of shareholders' investments could decline.

The trading price and value of, and demand for, the Corporation's Common Shares will fluctuate and depend on a number of factors, including:

- the risk factors described in this AIF;

- general economic conditions internationally and within Canada and the United States, including changes in interest rates;
- changes in electricity and natural gas prices;
- actual or anticipated fluctuations in the Corporation's quarterly and annual results and those of the Corporation's competitors;
- the Corporation's businesses, operations, results and prospects;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in government regulation, taxes, legal proceedings or other developments;
- shortfalls in the Corporation's operating results from levels forecasted by securities analysts;
- investor sentiment toward the stock of energy companies in general;
- announcements concerning the Corporation or its competitors;
- maintenance of acceptable credit ratings or credit quality; and
- the general state of the securities markets.

These and other factors may impair the development or sustainability of a liquid market for the Common Shares and the ability of investors to sell shares at an attractive price. These factors also could cause the market price and demand for the Common Shares to fluctuate substantially, which may adversely affect the price and liquidity of the Corporation's Common Shares. These fluctuations could cause shareholders to lose all or part of their investment in Common Shares. Many of these factors and conditions are beyond the Corporation's control and may not be related to its operating performance.

5. DIVIDENDS

Common Shares

The amount of dividends declared for each Common Share for fiscal 2015, 2016 and 2017 were U.S. $0.38, U.S. $0.41 and U.S. $0.47 respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 per Common Share per annum.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time at its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors previously noted, and there is no assurance as to the amount or timing of such dividends in the future. See "Enterprise Risk Factors".

Preferred Shares

On November 9, 2012, APUC issued 4,800,000 cumulative rate reset Series A preferred shares (the "**Series A Shares**"). For an initial six year period the holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.1250 per Series A Share. In each of 2015, 2016 and 2017, dividends of $1.1250 per Series A Share were paid.

On January 1, 2013, the Corporation issued 100 Series C Shares and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by the Senior Management. The Series C Shares provide dividends essentially identical to that expected from the Class B units. In 2015, 2016 and 2017, dividends paid to Series C preferred shareholders were $9,893, $8,528 and $7,922 per Series C Share respectively.

On March 5, 2014, APUC issued 4,000,000 cumulative rate reset Series D shares (the "**Series D Shares**"). For an initial five year period the holders of Series D Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.250 per Series D Share. In 2015, 2016, and 2017, dividends of $1.25 per Series D Share were paid.

5.1 Dividend Reinvestment Plan

Under the Reinvestment Plan, holders of Common Shares who reside in Canada or the United States may opt to reinvest the cash dividends paid on their Common Shares in additional Common Shares which, at APUC's election, will either be purchased on the open market or newly issued from treasury. Common Shares purchased under the Reinvestment Plan are currently being issued from treasury at a 5% discount to the prevailing market price (as determined in accordance with the terms of the Reinvestment Plan). The 5% discount will remain in effect for all cash dividends that may be declared, if any, by the Board until otherwise announced, at its discretion.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

The Common Shares are publicly traded on the TSX and the NYSE under the ticker symbol "**AQN**". The Corporation has been a U.S. Securities and Exchange Commission registrant since 2009 and operates primarily in the United States.

As at December 31, 2017, APUC had 431,765,935 issued and outstanding Common Shares.

APUC may issue an unlimited number of Common Shares. The holders of Common Shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of Common Shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

6.2 Preferred Shares

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2017, APUC had outstanding:

- 4,800,000 Series A Shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C Shares; and
- 4,000,000 Series D Shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

Series A Shares

The Series A Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on December 31, 2018 and on December 31 every five years thereafter, are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series B (the "**Series B Shares**"). The Series A Shares rank on a parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series A Shares are entitled to receive $25.00 per Series A Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series B Shares

APUC is authorized to issue up to 4,800,000 Series B Shares upon the conversion of Series A Shares upon the occurrence of certain events. Series B Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series B Conversion Date (as defined in the articles of APUC), and are convertible into Series A Shares upon the occurrence of certain events. The Series B Shares rank on a parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series B Shares are entitled to receive $25.00 per Series B Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series C Shares

The Series C preferred shares (the "**Series C Shares**") rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and are entitled to cumulative dividends in accordance with the formula set forth in the articles of APUC. The Series C Shares rank on a parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series C Shares are entitled to receive the redemption price calculated in accordance with the share terms plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. The Series C Shares are redeemable upon the occurrence of certain events. During the period between May 20, 2031 and June 19, 2031, the Series C Preferred Shares are convertible into Common Shares and, if not so converted, will be automatically redeemed on June 19, 2031. Holders of the Series C Preferred Shares include a partnership controlled by Ian Robertson, Chief Executive Officer of the Corporation and a partnership controlled by Chris Jarratt, Vice Chairman of the Corporation.

Series D Shares

The Series D Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on March 31, 2019 and on March 31 every five years thereafter, and are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series E (the "**Series E Shares**"). The Series D Shares rank on a parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series D Shares are entitled to receive $25.00 per Series D Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series E Shares

APUC is authorized to issue up to 4,000,000 Series E Shares upon the conversion of Series D Shares upon the occurrence of certain events. The Series E Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series E Conversion Date (as defined in the articles of APUC), and are convertible into Series D Shares upon the occurrence of certain events. The Series E Shares rank on a parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series E Shares are entitled to receive $25.00 per Series E Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Subject to applicable corporate law, the outstanding preferred shares are non-voting and not entitled to receive notice of any meeting of shareholders, except that the Series A Shares and Series D Shares (and the Series B Shares and Series E Shares, respectively, into which they are convertible) will be entitled to one vote per share if APUC shall have failed to pay eight quarterly dividends on such shares. **The outstanding preferred shares do not have a right to participate in a take-over bid of the Common Shares of APUC.**

6.3 Convertible Debentures

On February 9, 2016, in connection with the Empire Acquisition, APUC completed the sale of the Debentures.

The Debentures will mature on March 31, 2026. The Debentures accrued interest at an annual rate of 5% per $1,000 dollars principal amount of Debentures until and including February 2, 2017, after which the interest rate became 0%.

At the option of the holders, each Debenture is convertible into Common Shares at any time prior to the earlier of maturity or redemption by APUC, at a conversion price of $10.60 per Common Share. APUC will issue up to 108,490,566 Common Shares on conversion of all of the Debentures. To date, a total of 108,384,716 Common Shares were issued, representing conversion into Common Shares of more than 99.9% of the Debentures. At maturity, APUC will have the right to pay the principal amount due in cash or in Common Shares. In the case of Common Shares, such shares will be valued at 95% of their weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

6.4 Shareholders' Rights Plan

The shareholders' rights plan, as amended and restated in 2016 (the "**Amended and Restated Rights Plan**") is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value.

Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it (subject to certain exceptions), acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the permitted bid provisions of the Plan. Should a non-permitted bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

It is not the intention of the Amended and Restated Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Amended and Restated Rights Plan, a permitted bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 105 days. If at the end of 105 days at least fifty percent of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further ten days to allow all other shareholders to tender.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2019 or its termination under the terms of the of Amended and Restated Rights Plan. The Amended and Restated Rights Plan is similar to rights plans adopted by many other Canadian corporations.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

7.1.1 Common Shares

The Common Shares are listed and posted for trading on the TSX and NYSE under the symbol "AQN". The following table sets forth the high and low trading prices and the aggregate volumes of trading of the Common Shares for the periods indicated (as quoted by the TSX and NYSE).

		TSX			NYSE	
2017	High ($)	Low ($)	Volume	High (US$)	Low (US$)	Volume
January	11.48	11.15	37,934,616	8.79	8.33	347,242
February	12.29	11.33	28,660,212	9.35	8.68	355,634
March	12.98	11.98	24,143,635	9.71	9.00	323,442
April	13.05	12.57	17,211,371	9.74	9.38	242,782
May	13.98	12.90	19,040,345	10.35	9.44	282,999
June	14.35	13.26	16,660,457	10.80	10.21	273,733
July	13.70	12.90	18,919,660	10.85	10.00	316,009
August	13.83	13.10	12,252,860	11.02	10.33	327,519
September	13.59	12.91	17,566,633	11.20	10.50	447,560
October	14.145	13.18	18,200,984	11.21	10.56	500,870
November	14.40	12.99	30,208,784	11.34	10.13	813,669
December	14.33	13.86	15,101,341	11.22	10.80	472,775

7.1.2 Preferred Shares

Series A Shares

The Series A Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.A". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

2017	High ($)	Low ($)	Volume
January	21.59	19.62	71,411
February	22.00	21.45	76,083
March	22.77	21.34	130,552
April	23.15	21.68	52,280
May	22.82	21.62	108,755
June	23.44	22.11	154,745
July	24.43	23.15	325,970
August	24.02	22.55	190,566
September	23.34	22.50	42,044
October	24.00	23.00	84,596
November	24.20	23.10	59,700
December	24.10	23.52	39,533

Series D Shares

The Series D Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.D". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

2017	High ($)	Low ($)	Volume
January	24.32	22.90	133,516
February	24.42	23.80	114,078
March	24.62	22.95	86,538
April	24.50	23.73	19,168
May	24.40	23.16	48,047
June	24.59	23.40	55,076
July	25.00	24.22	163,059
August	24.92	23.63	46,036
September	25.05	23.81	40,283
October	25.30	25.00	33,432
November	25.98	25.14	24,310
December	25.50	24.90	96,914

7.2 Prior Sales

During the year ended December 31, 2017, there were no Series C Shares issued by APUC.

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

There are no securities of APUC that are subject to contractual restrictions on transfer as of the date of this AIF.

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with APCo and APUC. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 67	Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are boutique investment banking firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, was a director of Clean Energy BC, and is a recipient of the Clean Energy BC Lifetime Achievement Award.	Director of APUC since October 27, 2009 Trustee of APCo from October 22, 2002 until May 12, 2011
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 58	Mr. Bronicheski is the Chief Financial Officer of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA (University of Toronto, Rotman School of Management). He is also a Chartered Accountant and a Chartered Professional Accountant.	Officer of APUC since October 27, 2009 Officer of APCo since September 17, 2007
CHRISTOPHER K. JARRATT Oakville, Ontario, Canada Age: 59	Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors and is Vice Chair of APUC. Mr. Jarratt is a founder and principal of APCI, a private independent power developer formed in 1988 which is the predecessor organization to APCo and APUC. Between 1997 and 2009, Mr. Jarratt was a principal in Algonquin Power Management Inc. which managed APCo (formerly Algonquin Power Income Fund). Since 2010, Mr. Jarratt has been a board member and served as Vice Chair of APUC. Prior to 1988, Mr. Jarratt was a founder and principal of a consulting firm specializing in renewable energy project development and environmental approvals. Mr. Jarratt earned an Honours Bachelor of Science degree from the University of Guelph in 1981 specializing in water resources engineering and holds an Ontario Professional Engineering designation. In 2009, Mr. Jarratt completed the Chartered Director program of the Directors College (McMaster University) and holds the certification of Ch. Dr. (Chartered Director). In addition, Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award.	Director of APUC since June 23, 2010
D. RANDY LANEY Farmington, Arkansas, USA Age: 63	D. Randy Laney was most recently Chairman of the Board of Empire District Electric Company since 2009. He joined the Board of Empire in 2003 serving as the Non-Executive Vice Chairman of the Board from 2008 to 2009 and Non-Executive Chairman of the Board from April 23, 2009 until APUC's acquisition of Empire on January 1, 2017. Mr. Laney, semi-retired since 2008, has held numerous senior level positions with both public and private companies during his career, including 23 years with Wal-Mart Stores, Inc. in various executive positions including Vice President of Finance, Benefits and Risk Management and Vice President of Finance and Treasurer. In addition, Mr. Laney has provided strategic advisory services to both private and public companies and served on numerous profit and non-profit boards. Mr. Laney brings significant management and capital markets experience, and strategic and operational understanding to his position on the Board.	Director of APUC since February 1, 2017
KENNETH MOORE Toronto, Ontario, Canada Age: 59	Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009 Trustee of APCo from December 18, 1998 until November 10, 2010

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
JEFF NORMAN Burlington, Ontario, Canada Age: 49	Jeff Norman is the Chief Development Officer of the Corporation, serving in this role since 2008. He was appointed to the APUC executive team in 2015. Mr. Norman co-founded the Algonquin Power Venture Fund in 2003 and served as President until it was acquired by APCo in 2008. Since 2008 the business development team has secured over 1 gigawatt of commercially secure renewable energy projects. Mr. Norman has over 24 years of experience and has reviewed the economic merits of hundreds of renewable energy projects located throughout North America.	Officer of APUC since May 25, 2015
DAVID PASIEKA Oakville, Ontario, Canada Age: 61	David Pasieka is the Chief Operating Officer of APUC's Liberty Utilities Group. As Chief Operating Officer, Mr. Pasieka is focused on acquiring and managing a portfolio of regulated water, natural gas and electrical companies throughout the United States. The focus of the portfolio is in the distribution, transmission, and generation sectors. Mr. Pasieka has global experience in strategy, sales, marketing, integration, operations and customer service. He has led many organizations while integrating people, process and technology to encourage the steady growth of the organizations. Mr. Pasieka holds a Bachelor of Science Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business – York University and a Chartered Director designation from McMaster University.	Officer of APUC since September 1, 2011
IAN E. ROBERTSON Oakville, Ontario, Canada Age: 58	Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of APCI, a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has almost 30 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto and has the certification of Ch. Dir. (Chartered Director). Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association.	Director of APUC since June 23, 2010.
MASHEED SAIDI Dana Point, California, United States Age: 63	Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Between 2010 and 2017, Ms. Saidi was an Executive Consultant of Energy Initiatives Group, a specialized group of experienced professionals that provide technical, commercial and business consulting services to utilities, ISOs, government agencies and other organizations in the energy industry. Between 2005 and 2010, Ms. Saidi was the Chief Operating Officer and Executive Vice President of U.S. Transmission for National Grid USA, for which she was responsible for all aspects of U.S. transmission business. Ms. Saidi previously served as Chairperson of the Board of Directors for the non-profit organization, Mary's Shelter, and also previously served on the Board of Directors of the Northeast Energy and Commerce Association. She earned her Bachelors in Power System Engineering from Northeastern University and her Masters of Electrical Engineering from the Massachusetts Institute of Technology. She is a Registered Professional Engineer (P.E.).	Director of APUC since June 18, 2014
DILEK SAMIL Las Vegas, Nevada, United States Age: 62	Dilek Samil has over 30 years of finance, operations and business experience in both the regulated energy utility sector as well as wholesale power production. Ms. Samil joined NV Energy as Chief Financial Officer and retired as Executive Vice President and Chief Operating Officer. While at NV Energy, Ms. Samil completed the financial transformation of the company, bringing its financial metrics in line with those of the industry. As Chief Operating Officer, Ms. Samil focused on enhancing the company's safety and customer care culture. Prior to her role at NV Energy, Ms. Samil gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power. During her tenure at CLECO, the company completed construction of its largest generating unit and successfully completed its first rate case in over 10 years. Ms. Samil also served as CLECO's Chief Financial Officer at a time when the industry and the company faced significant turmoil in the wholesale markets. She led the company's efforts in the restructuring of its wholesale and power trading activities. Prior to NV Energy and Cleco, Ms. Samil spent about 20 years at NextEra where she held positions of increasing responsibility, primarily in the finance area. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.	Director of APUC since October 1, 2014

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
MIKE SNOW Markham, Ontario, Canada Age: 57	Mike joined APUC in 2011 and serves as Chief Operating Officer of APUC's Liberty Power Group. He is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mike has led both industrial and consumer organizations focused on growth and international operations in Mexico, South America, and Asia, while driving culture change and building strong leadership teams. Mike holds a Bachelor of Science Degree in Math from Dalhousie University, a Bachelor of Engineering Degree (Mechanical) from the Technical University of Nova Scotia, and a Masters of Business Administration from the Ivey School of Business - Western University. Mike received his Chartered Director designation from McMaster University in 2014 and sits on the Board of Governors of the University of Ontario Institute of Technology.	Officer of APUC since July 4, 2011
MELISSA STAPLETON BARNES Age: 49 Carmel, Indiana, United States of America	Melissa Stapleton Barnes has been Senior Vice President, Enterprise Risk Management, and Chief Ethics and Compliance Officer for Eli Lilly and Company since January, 2013. Reporting directly to the CEO and Board of Directors, she is an executive officer and serves as a member of the company's executive committee. She previously held the role of Vice President, Deputy General Counsel from 2012 to 2013; and General Counsel, Lilly Diabetes and Lilly Oncology and Senior Director and Assistant General Counsel from 2010 - 2012. She holds a Bachelor of Science in Political Science & Government (highest distinction) from Purdue University and a Juris Doctorate from Harvard Law School. Ms. Barnes is a member of several professional organizations including Ethisphere - Business Ethics Leadership Alliance; CEB, Corporate Ethics Leadership Council; Conference Board, Global Council on Business Conduct; Healthcare Businesswomen's Association, and is a Licensed Attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Vice Chair), Visit Indy, The Children's Museum, and The Great American Songbook.	Director of APUC since June 9, 2016
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 68	George Steeves has been Senior Project Manager of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects, since July 2017. From April 2002 to July 2017, Mr. Steeves was principal of True North Energy. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the President of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009 Trustee of APCo from September 8, 1997 until May 12, 2011
JENNIFER TINDALE Campbellville, Ontario, Canada Age: 46	Jennifer Tindale is the Chief Legal Officer of the Corporation. Ms. Tindale has over 20 years of experience advising public companies on acquisitions, dispositions, mergers, financings, corporate governance and disclosure matters. From July, 2011 to February, 2017, Ms. Tindale was the Executive Vice President, General Counsel & Secretary at a cross-listed real estate investment trust. Prior to that, she was Vice President, Associate General Counsel & Corporate Secretary at a public Canadian-based pharmaceutical company and before that she was a partner at a top tier Toronto law firm, practising corporate securities law. Ms. Tindale holds a Bachelor of Arts and a Bachelor of Laws from the University of Western Ontario.	Officer of APUC since February 7, 2017
GEORGE TRISIC Oakville, Ontario, Canada Age: 57	George Trisic is the Chief Administrative Officer and Corporate Secretary for the Corporation. He has broad experience managing in high growth, start up and expanding businesses across multiple sites and regions. In his role, Mr. Trisic is responsible for shared services for the Corporation including information technology, human resources, communications, and procurement, and is a well-regarded team builder and business partner. His skill set includes leading multi-functional groups in finance, human resources, legal, and information technology in a senior role. Mr. Trisic holds a Bachelor of Laws Degree from the University of Western Ontario. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Officer of APUC since November 4, 2013

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his or her successor is elected in accordance with the by-laws of APUC.

As at March 7, 2018, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 5,091,086 Common Shares, representing less than one percent of the total number of

Common Shares outstanding before giving effect to the exercise of options or warrants to purchase Common Shares held by such directors and executive officers. The statement as to the number of Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised by the directors and executive officers of APUC as a group is based upon information furnished by the directors and executive officers.

8.2 Audit Committee

Under the by-laws of APUC, the directors may appoint from their number, committees to effect the administration of the director's duties. The directors have established an Audit Committee currently comprised of four directors of APUC, Mr. Ball (Chair), Ms. Stapleton Barnes, Mr. Laney and Ms. Samil, all of whom are independent and financially literate for purposes of National Instrument 52-110 - Audit Committees. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

8.2.1 Audit Committee Charter

The charter for the Audit Committee is attached as Schedule F to this AIF.

8.2.2 Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as directors of APUC, of each member of the Audit Committee that is relevant to the performance of their responsibilities as a member of the Audit Committee.

Mr. Ball's financial experience includes over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Laney's financial experience includes a number of senior executive roles with Wal-Mart Stores, Inc. including roles as Vice President, Finance and Treasurer and as Vice President Finance, Benefits and Risk Management. Mr. Laney has also served as member of the Board of the Empire District Electric Company commencing in 2003 and as board Chair of that company from 2009 to 2016. Mr. Laney was also a member of the Audit Committee of the Empire District Electric Company from May 2003 to April 2005.

Ms. Samil has extensive financial experience, with over 30 years of finance, operations and business experience in the regulated energy utility sector. During her career, Ms. Samil was the Executive Vice President and Chief Operating Officer of NV Energy and gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power LLC. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.

Ms. Stapleton-Barnes' financial experience includes a number of risk management and legal/regulatory senior executive roles in a public company. Ms. Stapleton-Barnes is currently an executive officer and a member of the corporate executive committee of Eli-Lilly and Company. She has extensive experience in the areas of risk management, legal and regulatory and is a licensed attorney with the Indiana State Bar.

8.2.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy requiring pre-approval by the Audit Committee of all audit and permitted non-audit services provided to APUC by its external auditor. The Audit Committee may delegate pre-approval authority to a member of the Audit Committee; however, the decisions of any member of the Audit Committee to whom this authority has been delegated must be presented to the full Audit Committee at its next scheduled Audit Committee meeting.

Services	2017 Fees ($)	2016 Fees ($)	2015 Fees ($)
Audit Fees[1]	3,947,930	3,184,020	2,420,650
Audit-Related Fees[2]	100,235	113,414	98,835
Other Tax Fees[3]	252,535	269,631	395,100

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements.

2 For assurance and related services that are reasonably related to the performance of the audit or review of APUC's financial statements and not reported under Audit Fees, including audit procedures related to regulatory commission filings and translation services.

3 For tax advisory and planning services.

8.3 Corporate Governance, Risk and Compensation Committees

The Board has established a Corporate Governance Committee, currently comprised of four of the directors of APUC: Mr. Steeves (Chair), Mr. Moore, Ms. Saidi, and Mr. Jarratt.

In 2017, the Board has established a Risk Committee to assist the board in the oversight of the Corporation's enterprise risk management approach. The committee is currently comprised of four directors of APUC, Ms. Saidi (Chair), Ms. Stapleton Barnes, Mr. Jarratt and Mr. Steeves.

The directors have also put in place a Compensation Committee, currently comprised of three directors of APUC, Ms. Samil (Chair), Mr. Ball and Mr. Laney.

8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media company. Telephoto Technologies Inc. was placed into receivership in August, 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April, 2010.

8.5 Potential Material Conflicts of Interest

Other than as disclosed elsewhere in this AIF (see "*Description of the Business - Related Party Transactions*"), to the knowledge of the directors and executive officers of APUC there are no existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary of APUC.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, there are no legal proceedings involving the Corporation that were material in 2017 or that the Corporation knows to be contemplated.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2017, there have been:

(a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

Except as disclosed elsewhere in this AIF, the only regulatory action involving the Corporation that was material in 2017 is as follows:

(i) Mountain Water Condemnation

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("**Carlyle**"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. $88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have appealed certain elements of the final order of condemnation including, among other issues, recovery of post-summons interest and attorney's fees.

(ii) Apple Valley Condemnation

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to acquire a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act (CEQA) lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Utilities (Apple Valley Ranchos Water) Corp.s CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case in March, 2018 to potentially set a trial date on the first phase of the condemnation action.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed elsewhere in this AIF, no director, executive officer or principal holder of securities, or any associate or affiliate of the foregoing has, or has had, any material interest in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC or any of its affiliates.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares, the Series A Shares, and the Series D Shares listed on the TSX is AST Trust Company (Canada), at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

The transfer agent and registrar for the Common Shares listed on the NYSE is AST American Stock Transfer & Trust Company, LLC, at its office in Brooklyn, NY.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of the Corporation, the contracts described below are the only contracts entered into by the Corporation during 2017 (or prior to 2017 in the case of contracts that are still in effect) that are material to the Corporation:

(a) **Atlantica Share Purchase Agreement:** APUC entered into a sale and purchase agreement dated November 2, 2017, as amended, with ACIL Luxco 1, S.A. and Abengoa providing for the purchase by APUC from ACIL Luxco 1, S.A. of a 25% equity interest in Atlantica for a total purchase price of approximately U.S. $608 million plus a contingent payment payable two years after closing, subject to certain conditions. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017"*.

(b) **Underwriting Agreement**: Underwriting Agreement dated November 3, 2017, between APUC and Scotia Capital Inc., CIBC World Markets Inc. and TD Securities Inc. as co-lead underwriters, in connection with an offering of Common Shares which closed on November 10, 2017. See "*General Development of the Business – Fiscal 2017 – Bought Deal Offering of Common Shares"*.

(c) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures, as supplemented from time to time, including by the Fourth Supplemental Trust Indenture dated January 17, 2017 providing for the issuance of $300,000,000 4.09% senior unsecured debentures due February 17, 2027.

(d) **U.S. Debt Private Placements**: Trust Indenture dated July 2, 2012 between Liberty Utilities Finance GP 1 and The Bank of New York Mellon providing for the creation and issuance of senior unsecured debentures, as supplemented from time to time.

(e) **Empire Acquisition**: Agreement and Plan of Merger, dated as of February 9, 2016, by and among Empire, Liberty Utilities (Central) Co., and Liberty Utilities (Sub) Corp. pursuant to which Liberty Utilities (Central) Co. agreed to acquire Empire and (indirectly) its subsidiaries by merger of Liberty Sub Corp. with and into Empire. APUC guaranteed the payment and performance of all obligations of Liberty Utilities (Central) Co. under the Agreement and Plan of Merger pursuant to a Guarantee dated as of February 9, 2016, by APUC in favour of Empire.

(f) **Underwriting Agreement**: Underwriting Agreement dated February 15, 2016, between LU Canada, as the selling debenture holder, and CIBC World Markets Inc. and Scotia Capital Inc. as co-lead underwriters, providing for the issuance and sale of not less than $1,000,000,000 and up to $1,150,000,000 principal amount of Debentures in connection with the Debenture Offering.

(g) **Trust Indenture**: Trust Indenture dated as of March 1, 2016, between APUC and CST Trust Company, as trustee, providing for the creation and issuance of up to $1,150,000,000 principal amount of Debentures in connection with the Debenture Offering, as supplemented by a supplemental trust indenture dated January 31, 2017.

13. INTERESTS OF EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and has confirmed that it is independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that it is an independent accountant with respect to the Corporation under all relevant U.S. professional and regulatory standards.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and MD&A for the fiscal year ended December 31, 2017, which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

SCHEDULE A

Renewable – Selected Hydroelectric, Solar and Wind Facilities

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year
Facility: Dickson Dam Hydro Facility **Owner:** Algonquin Power Operating Trust	15	Innisfail, Alberta	AESO	N/A
Facility: Tinker Hydro Facility **Owner**: Algonquin Tinker Gen Co.	34	Perth-Andover, New Brunswick	Algonquin Energy Services Inc. Town of Perth-Andover	Perth-Andover Contract through 2031
Facility: Bakersfield I Solar Facility **Owner**: Algonquin SKIC20 Solar, LLC	20	Kern County, California	Pacific Gas & Electric Company	2035
Facility: Great Bay Solar Facility **Owner**: Great Bay Solar I, LLC	75	Somerset County, Maryland	Under Development - U.S. General Services Administration	2028 (10 years after COD)
Facility: St. Leon Wind Facility **Owner**: St. Leon Wind Energy LP	103.9	St. Leon, Manitoba	Manitoba Hydro	2026 + one 5 year extension
Facility: Amherst Island Wind Project **Owner**: Windlectric Inc.	75	Stella, Ontario	Under Development - IESO	2038 (20 years after COD)
Facility: Blue Hill Wind Project **Owner**: Blue Hill Wind Energy Project Partnership	177	Lawtonia, Saskatchewan	Under Development - SaskPower	2044/5 (25 years after COD)
Facility: Minonk Wind Facility **Owner**: Minonk Wind, LLC	200	Minonk, Illinois	PJM North Illinois	2023 [1]
Facility: Senate Wind Facility **Owner:** Senate Wind, LLC	150	Graham, Texas	ERCOT North markets	2027 [1]
Facility: Sandy Ridge Wind Facility **Owner:** Sandy Ridge Wind, LLC	50	Tyrone, Pennsylvania	PJM West	2023 [1]

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year
Facility: Shady Oaks Wind Facility **Owner:** GSG 6, LLC	109.5	Lee County, Illinois	Commonwealt h Edison	2032
Facility: Odell Wind Facility **Owner**: Odell Wind Farm, LLC.	200	Cottonwood, Jackson, Martin and Watonwan Counties, Minnesota	Northern States Power	2036
Facility: Deerfield Wind Facility **Owner**: Deerfield Wind Energy, LLC	150	Central Michigan	Wolverine Power Supply Co-operative	2037

[1] The Corporation currently has hedge agreements in place in respect of each facility. See "Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities".

SCHEDULE B

Selected Thermal – Biomass, Cogeneration, and Diesel Facilities

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year	Lease Expiry Year
Facility: Sanger Facility **Owner**: Algonquin Power Sanger LLC	56	Sanger, California	Pacific Gas & Electric Company	2021	Owned
Facility: Windsor Locks Facility **Owner**: Algonquin Power Windsor Locks LLC	71	Windsor Locks, Connecticut	ISO New England Ahlstrom Corporation	2027	2027

SCHEDULE C

Selected Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
LPSCo System	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Litchfield, Park, Arizona	Wastewater Water Distribution	Pursuant to ACC docket 74437
Pine Bluff Water System	Liberty Utilities (Pine Bluff Water) Inc.	Pine Bluff, Arkansas	Water Distribution	Pursuant to APSC docket No. 14-020-U
Liberty Park Water System	Liberty Utilities (Park Water) Corp.	Downey, California	Water Distribution	Pursuant to CPUC decision 16-01-009
Apple Valley Water System	Liberty Utilities (Apple Valley Ranchos Water) Corp.	Apple Valley, California	Water Distribution	Pursuant to CPUC decision 15-11-030
Empire District Water System	The Empire District Electric Company	Joplin, Missouri	Distribution	MO – WR-2012-0300

1 See www.libertyutilities.com for complete rate tariffs.

SCHEDULE D

Selected Electrical Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
CalPeco Electric System	Liberty Utilities (CalPeco Electric) LLC	Lake Tahoe, California	Electricity Distribution	Rates pursuant to CPUC decision 16-12-024
Granite State Electric System	Liberty Utilities (Granite State Electric) Corp	Salem, New Hampshire	Electricity Distribution	Rates pursuant to NHPUC docket DE 13-063, Order 25,638 and docket DE 16-383, Order 26,005
Empire District Electric System	The Empire District Electric Company	Joplin, Missouri	Electricity Generation, Transmission & Distribution	MO - ER-2016-0023 AR - 13-111-U KS - 11-EPDE-856-RTS OK - PUD 201600468

[1] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE E

Selected Natural Gas Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
EnergyNorth Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Londonderry, New Hampshire	Natural Gas Distribution	Rates pursuant to NHPUC docket DG 14-180, Order 25,797
Peach State Gas System	Liberty Utilities (Peach State Natural Gas) Corp.	Columbus, Gainesville, Georgia	Natural Gas Distribution	Rates pursuant to GPSC docket #34734 Document #166,984
New England Gas System	Liberty Utilities (New England Natural Gas Company) Corp.	Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts	Natural Gas Distribution	Rates pursuant to D.P.U 15-75
Midstates Gas System	Liberty Utilities (Midstates Natural Gas) Corp.	Salem, Virden, Vandalia, Xenia, Metropolis, Illinois Keokuk, Iowa Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Rates pursuant to ICC decision IL-16-0401 Rates pursuant to IUB decision RPU-2016-0003 Rates pursuant to MOPSC decision GR-2014-0152
New Hampshire Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Keene, New Hampshire	Propane Gas Distribution	Rates pursuant to NHPUC docket DG 09-038
Empire District Gas System	The Empire District Gas Company	Joplin, Missouri	Natural Gas Distribution	MO - GR-2009-0434

[1] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE F

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the "**Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the "**Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

1 PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis ("**MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

2 COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

(a) be a director of the Corporation;

(b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates; and

(c) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under NI 52 110 and other applicable laws and regulations.

2.4 Chair – The Chair of the Committee shall be selected from among the members of the Committee.

2.5 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

3 COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly and meetings of the Committee shall be convened whenever requested by the external auditors or any member of the Committee in accordance with the Canada Business Corporations Act. No business may be transacted by the Committee at a meeting unless a quorum of a majority of the members of the Committee is present. The Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall hold *in camera* meetings, and shall also meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to receive notice of every Committee meeting and to be heard and attend thereat at the Corporation's expense. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

4 COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such outside legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this mandate.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

5 REMUNERATION OF COMMITTEE MEMBERS

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6 DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

(a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) <u>Interim Financial Statements</u> – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) <u>Prospectuses and Other Documents</u> – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) <u>Accounting Treatment</u> – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Corporation's selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

(G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

(A) review earnings releases, and review and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor

(i) Authority with Respect to External Auditor – As a representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, for determining whether at any time the incumbent external auditor should be removed from office, and for determining the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Committee may delegate to one or more designated members of the Committee, such designated members not being members of management, the authority to approve additional non‑audit services that arise between Committee meetings, provided that such designated members report any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems advisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to assess compliance by the Corporation with its loan covenants and restrictions, if any.

(e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non-compliance by the Corporation with applicable laws and regulations.

(f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(h) Liaison – The Committee shall assess whether appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(i) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

(j) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7 REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8 EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Mandate

(a) Review by Committee – The Committee shall periodically review and discuss the adequacy of this mandate and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the mandate periodically, as it considers appropriate.

9 LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board's intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this mandate shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least every fourteen months to reflect such amendments.

10 CURRENCY OF MANDATE

10.1 Currency of Mandate – This mandate was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 1, 2018.

SCHEDULE G

GLOSSARY OF TERMS

In this AIF, the following terms have the meanings set forth below, unless otherwise indicated:

"**AAGES**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 - Corporate".*

"**AAGES Preferred Shares**" has the meaning ascribed thereto under *"Description of the Business – Portfolio Investments"*.

"**Abengoa**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 - Corporate".*

"**ACC**" means the Arizona Corporation Commission.

"**ADEQ**" means Arizona Department of Environmental Quality.

"**Adjusted EBITDA**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

"**AESO**" means Alberta Electric System Operator.

"**AIF**" means this annual information form.

"**Amended and Restated Rights Plan**" has the meaning ascribed thereto under *"Description of Capital Structure – Shareholders' Rights Plan".*

"**Amherst Island Wind Project**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

"**APCI**" means Algonquin Power Corporation Inc.

"**APCo**" has the meaning ascribed thereto under *"Corporate Structure - Name, Address and Incorporation"*.

"**Apple Valley**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Apple Valley Water System**" means the Apple Valley Ranchos water facility in Apple Valley, California.

"**APSC**" means Arkansas Public Services Commission.

"**APUC**" has the meaning ascribed thereto under *"Corporate Structure - Name, Address and Incorporation"*.

"**Atlantica**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 - Corporate".*

"**AY Shares**" has the meaning ascribed thereto under *"Description of the Business – Portfolio Investments"*.

"**Bakersfield I Solar Facility**" means the 20 MW Bakersfield solar generating facility in California.

"**Bakersfield II Solar Facility**" means the 10 MW Bakersfield solar generating facility in California.

"**Blue Hill Wind Project**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

"**Board**" means the Algonquin Power & Utilities Corp. Board of Directors.

"**BRRBA**" means base revenue requirement balancing account.

"**CAISO**" means California Independent System Operation.

"**CalPeco Electric System**" means the electricity distribution utility in the Lake Tahoe basin and surrounding areas.

"**Carlyle**" has the meaning ascribed thereto under the heading "*Legal Proceedings and Regulatory Actions - Regulatory Actions – Mountain Water Condemnation*".

"**CEQA**" means California Environmental Quality Act.

"**COD**" means commercial operation date.

"**Common Shares**" means the common shares of Algonquin Power & Utilities Corp.

"**Cornwall Solar Facility**" means the solar generating facility in Cornwall, Ontario.

"**Corporation**" has the meaning ascribed thereto under *"Corporate Structure - Name, Address and Incorporation"*.

"**CPCN**" means Certificate of Public Convenience and Necessity.

"**CPUC**" means California Public Utilities Commission.

"**DBRS**" means the credit rating agency Dominion Bond Rating Service Limited.

"**Debentures**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

"**Debenture Offering**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

"**Default Service**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Electric Distribution Systems - Material Facilities"*.

"**Deerfield Wind Facility**" means the Deerfield wind energy facility in Michigan.

"**Dickson Dam Hydro Facility**" means the Dickson hydroelectric generating facility in Alberta.

"**ECAC**" means energy cost adjustment clause.

"**EDG**" The Empire District Gas Company.

"**Empire**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Empire Acquisition**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

“**Empire Acquisition Facility**” has the meaning ascribed thereto under *“General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate”.*

“**EnergyNorth Gas System**” means a natural gas distribution utility in New Hampshire.

“**ERCOT**” means Electric Reliability Council of Texas.

“**ERM**” means enterprise risk management.

“**EUA**” means Electric Utilities Act (Alberta).

“**EWGs**” has the meaning ascribed thereto under *“Description of the Business – Liberty Power Group - Regulatory Regimes- Power Generation - United States”.*

“**FERC**” means the Federal Energy Regulatory Commission.

“**FIT**” means feed-in tariff.

“**FPA**” has the meaning ascribed thereto under *“Description of the Business - Liberty Power Group - Regulatory Regimes- Power Generation - United States”.*

“**Full PTC Projects**” has the meaning ascribed thereto under *“General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group Highlights”.*

“**GAAP**” means Generally Accepted Accounting Principles.

“**GAF**” has the meaning ascribed thereto under “*Description of the Business – Liberty Utilities Group – Description of Operations – Natural Gas Distribution Systems – Material Facilities*”.

“**GRAM**” means the Georgia Rate Adjustment Mechanism.

“**Great Bay Solar Project**” means the Great Bay solar facility in Somerset County, Maryland.

“**Granite State Electric System**” means an electrical distribution utility in New Hampshire.

“**Hydro-Québec**” means Hydro-Québec Distribution.

“**IESO**” means Independent Electricity System Operator.

“**ISO**” means independent system operator.

“**ISO-NE**” means Independent System Operator New England.

“**JPMVEC**” has the meaning ascribed thereto under “*Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities*”.

“**KCC**” means State Corporation Commission of the State of Kansas.

“**Liberty Park Water**” has the meaning ascribed thereto under *“Corporate Structure - Intercorporate Relationships”*.

“**Liberty Park Water System**” has the meaning ascribed thereto under *“General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Utilities Group”.*

"**Long Sault Hydro Facility**" means the Long Sault rapids hydroelectric generating facility.

"**LPSCo System**" means the Litchfield Park water and wastewater system in Arizona.

"**LU Canada**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Luning Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Utilities Group".*

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**MBR Authority**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**MD&A**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information"*.

"**MDPU**" means The Massachusetts Department of Public Utilities.

"**Midstates Gas Systems**" means natural gas distribution utility assets in Missouri, Iowa and Illinois.

"**Minonk Wind Facility**" means the Minonk wind energy facility in Illinois.

"**MISO**" means Midcontinent Independent System Operator, Inc.

"**Moody's**" means Moody's Investors Services, Inc.

"**Morse Wind Facility**" means the Morse wind facility in Saskatchewan.

"**MPSC**" means Missouri Public Services Commission.

"**MW**" means megawatt.

"**MWh**" means megawatt hours.

"**NB Power**" means New Brunswick Power Corporation.

"**NBSO**" means New Brunswick System Operator.

"**Net Energy Sales**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

"**Net Utility Sales**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

"**New England Gas System**" means natural gas distribution utility assets in Massachusetts.

"**NHPUC**" means the New Hampshire Public Utilities Commission.

"**NERC**" means the North American Electric Reliability Corporation.

"**NV Energy**" means NV Energy, Inc.

"**NYSE**" means New York Stock Exchange.

"**OATT**" means open access transmission tariff.

"**OCC**" means Corporation Commission of Oklahoma.

"**Odell Wind Facility**" means the 200 MW Odell wind facility in Cottonwood, Jackson, Martina and Watonwan counties in Minnesota.

"**OEB**" means the Ontario Energy Board.

"**OEFC**" means Ontario Electric Financial Corporation.

"**OPEB**" has the meaning ascribed thereto under "*Enterprise Risk Factors – Risk Factors Relating to Financing and Financial Reporting*".

"**OPG**" means Ontario Power Generation Inc.

"**Peach State Gas System**" means natural gas distribution utility assets in Georgia.

"**PGA**" means Purchased Gas Adjustment.

"**PJM**" means PJM Interconnection.

"**PPA**" means power purchase agreement.

"**Primary Energy Production Hedge**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities*".

"**PTC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group".*

"**PUHCA**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**QFs**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**REC**" means renewable energy credits.

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group".*

"**Reinvestment Plan**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 - Corporate".*

"**RPS**" means renewable portfolio standards.

"**RTO**" means regional transmission organization.

"**S&P**" means Standard & Poor's Financial Services LLC.

"**Saint-Damase Wind Facility**" means the Saint-Damase wind facility.

"**Sandy Ridge Wind Facility**" means the Sandy Ridge wind energy facility in Texas.

"**Senate Wind Facility**" means the Senate wind energy facility in Texas.

"**Series A Shares**" has the meaning ascribed thereto under "*Dividends - Preferred Shares".*

"**Series B Shares**" has the meaning ascribed thereto under *"Description of Capital Structure – Preferred Shares".*

"**Series C Shares**" has the meaning ascribed thereto under *"Description of Capital Structure – Preferred Shares".*

"**Series D Shares**" has the meaning ascribed thereto under *"Dividends - Preferred Shares".*

"**Series E Shares**" has the meaning ascribed thereto under *"Description of Capital Structure – Preferred Shares".*

"**Shady Oaks Wind Facility**" means the Shady Oaks wind energy facility in Illinois.

"**SLG**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Utilities Group".*

"**SPP**" means Southwest Power Pool.

"**SPP IM**" has the meaning ascribed thereto under "*Enterprise Risk Factors – Risk Factors Relating to Operations*".

"**St. Leon II Wind Facility**" means the 16.5 MW wind facility located at St. Leon, Manitoba.

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon Wind Facility**" means the 104 MW wind facility located at St. Leon, Manitoba.

"**SWRCB**" means the Division of Drinking Water of the California State Water Resources Control Board.

"**Tinker Hydro Facility**" means the electric generating facility and transmission assets in New Brunswick.

"**TSX**" means the Toronto Stock Exchange.

"**Val-Éo Wind Project**" "has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

"**Windsor Locks Facility**" has the meaning ascribed thereto under the heading *"Description of the Business - Liberty Power Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities"*.

Consolidated Financial Statements of

Algonquin Power & Utilities Corp.

For the years ended December 31, 2017 and 2016

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2017.

During the year ended December 31, 2017, APUC acquired The Empire District Electric Company and its subsidiaries ("Empire"). The financial information for this acquisition is included in note 3(a) to the consolidated financial statements. As permitted by National Instrument 52-109 and published guidance of the U.S. Securities and Exchange Commission (SEC), management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Empire, which are included in the 2017 consolidated financial statements of Algonquin Power and Utilities Corp. and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues for the year then ended.

March 7, 2018

/s/ Ian Robertson	/s/ David Bronicheski
Chief Executive Officer	Chief Financial Officer

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income/(loss), equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements").

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Report on internal control over financial reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 7, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2013.

Toronto, Canada
March 7, 2018

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on Internal Control over Financial Reporting

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, Algonquin Power & Utilities Corp. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information and our report dated March 7, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated under the heading Internal Controls over Financial Reporting in Management's Report, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Empire District Electric Corp. and its subsidiaries ("Empire"), which are included in the 2017 consolidated financial statements of the Company and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power and Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Empire.

/s/ Ernst & Young LLP

Toronto, Canada
March 7, 2018

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,550	$ 110,417
Accounts receivable, net (note 4)	306,872	189,658
Fuel and natural gas in storage (note 1(h))	55,718	21,625
Supplies and consumables inventory	56,546	15,568
Regulatory assets (note 7)	83,508	48,440
Prepaid expenses	38,896	26,562
Derivative instruments (note 25)	20,196	76,631
Other assets (note 12)	8,919	2,951
	625,205	491,852
Property, plant and equipment, net (note 5)	7,909,493	4,889,946
Intangible assets, net (note 6)	64,108	64,989
Goodwill (note 6)	1,196,234	306,641
Regulatory assets (note 7)	467,626	243,524
Derivative instruments (note 25)	67,888	74,553
Long-term investments (note 8)	84,467	105,433
Deferred income taxes (note 20)	76,972	30,005
Restricted cash (note 1(f))	19,995	2,026,183
Other assets (note 12)	21,647	16,334
	$10,533,635	$ 8,249,460

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 150,426	$ 90,592
Accrued liabilities	351,441	308,318
Dividends payable (note 17)	63,283	38,973
Regulatory liabilities (note 7)	47,278	47,769
Long-term debt (note 9)	15,511	10,075
Other long-term liabilities and deferred credits (note 13)	57,586	43,157
Derivative instruments (note 25)	17,721	4,178
Other liabilities	4,359	3,487
	707,605	546,549
Long-term debt (note 9)	3,847,785	3,903,340
Convertible debentures (note 14)	1,218	358,619
Regulatory liabilities (note 7)	677,778	134,965
Deferred income taxes (note 20)	499,819	288,139
Derivative instruments (note 25)	68,769	104,647
Pension and other post-employment benefits obligation (note 10)	210,994	147,845
Other long-term liabilities (note 13)	285,106	232,449
Preferred shares, Series C (note 11)	17,396	17,552
	5,608,865	5,187,556
Redeemable non-controlling interest (note 19)	52,128	29,434
Equity:		
Preferred shares (note 15(b))	213,805	213,805
Common shares (note 15(a))	3,713,037	1,972,203
Additional paid-in capital	43,204	38,652
Deficit	(617,836)	(556,024)
Accumulated other comprehensive income (note 16)	56,820	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	3,409,030	1,923,563
Non-controlling interests (note 19)	756,007	562,358
Total equity	4,165,037	2,485,921
Commitments and contingencies (note 23)		
Subsequent events (notes 9 and 15(a)(iii))		
	$10,533,635	$ 8,249,460

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2017	**2016**
Revenue		
Regulated electricity distribution	$ 989,221	$ 228,097
Regulated gas distribution	493,208	405,735
Regulated water reclamation and distribution	181,851	181,655
Non-regulated energy sales	282,558	243,149
Other revenue	30,971	37,382
	1,977,809	1,096,018
Expenses		
Operating expenses	598,658	333,001
Regulated electricity purchased	288,183	119,825
Regulated gas purchased	184,523	142,003
Regulated water purchased	12,310	12,227
Non-regulated energy purchased	25,384	21,260
Administrative expenses	64,466	46,349
Depreciation and amortization	326,447	186,899
Loss (gain) on foreign exchange	373	(436)
	1,500,344	861,128
Operating income	477,465	234,890
Interest expense on long-term debt and others	184,993	73,962
Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 14)	17,638	57,630
Interest, dividend, equity and other income	(11,989)	(10,573)
Other losses (gains) (note 23(a))	632	(11,818)
Acquisition-related costs	62,777	12,028
Gain on derivative financial instruments (note 25(b)(iv))	(2,626)	(15,849)
	251,425	105,380
Earnings before income taxes	226,040	129,510
Income tax expense (note 20)		
Current	9,908	8,461
Deferred	85,286	28,675
	95,194	37,136
Net earnings	130,846	92,374
Net effect of non-controlling interests (note 19)	62,248	38,550
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 193,094	$ 130,924
Series A and D Preferred shares dividend (note 17)	10,400	10,400
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 182,694	$ 120,524
Basic net earnings per share (note 21)	$ 0.48	$ 0.44
Diluted net earnings per share (note 21)	$ 0.47	$ 0.44

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2017	**2016**
Net earnings	$ 130,846	$ 92,374
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax recovery of $219 and $nil, respectively (notes 1(v), 25(b)(iii) and 25(b)(iv))	(256,067)	(67,855)
Change in fair value of cash flow hedges, net of tax expense of $756 and $18,109, respectively (note 25(b)(ii))	1,909	26,754
Change in value of available-for-sale investments	(141)	213
Change in pension and other post-employment benefits, net of tax expense of $717 and $1,433, respectively (note 10)	525	2,252
Other comprehensive loss, net of tax	(253,774)	(38,636)
Comprehensive (loss) income	(122,928)	53,738
Comprehensive loss attributable to the non-controlling interests	(117,915)	(45,376)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ (5,013)	$ 99,114

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2017

	Algonquin Power & Utilities Corp. Shareholders						
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2016	$1,972,203	$213,805	$ 38,652	$ (556,024)	$ 254,927	$562,358	$ 2,485,921
Net earnings (loss)	—	—	—	193,094	—	(62,248)	130,846
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	13,400	13,400
Other comprehensive loss	—	—	—	—	(198,107)	(55,667)	(253,774)
Dividends declared and distributions to non-controlling interests	—	—	—	(205,439)	—	(5,055)	(210,494)
Dividends and issuance of shares under dividend reinvestment plan (note 15(a)(iii))	47,470	—	—	(47,470)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 15(a)(i))	558,083	—	—	—	—	—	558,083
Common shares issued upon conversion of convertible debentures (note 14)	1,114,688	—	—	—	—	—	1,114,688
Common shares issued pursuant to share-based awards (note 15(c))	20,593	—	(6,527)	(1,997)	—	—	12,069
Share-based compensation (note 15(c))	—	—	11,079	—	—	—	11,079
Contributions received from non-controlling interests (notes 3(c), 3(g) and 8(b))	—	—	—	—	—	303,219	303,219
Balance, December 31, 2017	$3,713,037	$213,805	$ 43,204	$ (617,836)	$ 56,820	$756,007	$ 4,165,037

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2016

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	**Preferred shares**	**Subscription receipts**	**Additional paid-in capital**	**Accumulated deficit**	**Accumulated OCI**	**Non-controlling interests**	**Total**
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864
Net earnings (loss)	—	—	—	—	130,924	—	(38,550)	92,374
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	—	4,952	4,952
Other comprehensive income	—	—	—	—	—	(31,810)	(6,826)	(38,636)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(125,696)	—	(3,926)	(129,622)
Dividends and issuance of shares under dividend reinvestment plan	33,862	—	—	—	(33,862)	—	—	—
Common shares issued upon conversion of subscription receipts	110,503	—	(110,503)	—	—	—	—	—
Common shares issued pursuant to share-based awards (note 15(c))	18,944	—	—	(5,505)	(4,274)	—	—	9,165
Share-based compensation	—	—	—	5,916	—	—	—	5,916
Contributions received from non-controlling interests	—	—	—	—	—	—	12,752	12,752
Non-controlling interest of acquired operating entity	—	—	—	—	—	—	237,156	237,156
Balance, December 31, 2016	$1,972,203	$213,805	$ —	$ 38,652	$ (556,024)	$ 254,927	$562,358	$2,485,921

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2017	2016
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 130,846	$ 92,374
Adjustments and items not affecting cash:		
Depreciation and amortization	329,273	195,751
Deferred taxes	85,286	28,675
Unrealized loss (gain) on derivative financial instruments	1,764	(18,689)
Share-based compensation expense	10,630	5,916
Cost of equity funds used for construction purposes	(3,014)	(2,774)
Pension and post-employment contributions in excess of expense	(26,893)	(13,491)
Non-cash revenue and other income	—	(10,467)
Distributions received from equity investments, net of income	3,141	653
Write-down of long-lived assets	789	6,259
Changes in non-cash operating items (note 24)	(74,026)	3,704
	457,796	287,911
Financing Activities		
Increase in long-term debt	1,838,035	2,399,009
Decrease in long-term debt	(3,131,717)	(68,423)
Issuance of convertible debentures, net of costs	743,881	357,694
Cash dividends on common shares	(170,199)	(118,145)
Dividends on preferred shares	(10,400)	(10,400)
Contributions from non-controlling interests	333,395	13,468
Production-based cash contributions from non-controlling interest	10,622	9,454
Distributions to non-controlling interests	(4,135)	(4,307)
Issuance of common shares, net of costs	556,634	1,526
Proceeds from settlement of derivative assets	48,381	—
Proceeds from exercise of share options	12,761	18,461
Shares surrendered to fund withholding taxes on exercised share options	(4,401)	(5,218)
Increase in other long-term liabilities	33,030	6,486
Decrease in other long-term liabilities	(8,751)	(4,269)
	247,136	2,595,336
Investing Activities		
Decrease (increase) in restricted cash	2,011,204	(2,007,732)
Acquisitions of operating entities	(2,047,401)	(432,699)
Divestiture of operating entity	111,043	—
Additions to property, plant and equipment	(740,023)	(405,743)
Increase in other assets	(9,122)	(20,501)
Receipt of principal on notes receivable	—	319,160
Increase in long-term investments	(82,449)	(347,901)
	(756,748)	(2,895,416)
Effect of exchange rate differences on cash	(4,051)	(2,231)
Decrease in cash and cash equivalents	(55,867)	(14,400)
Cash and cash equivalents, beginning of year	110,417	124,817
Cash and cash equivalents, end of year	$ 54,550	$ 110,417

Supplemental disclosure of cash flow information:	**2017**	**2016**
Cash paid during the year for interest expense	$ 198,045	$ 131,783
Cash paid during the year for income taxes	$ 11,377	$ 13,369
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 141,708	$ 146,301
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 51,178	$ 35,409
Issuance of common shares upon conversion of convertible debentures	$ 1,102,304	$ —
Issuance of common shares upon conversion of subscription receipts	$ —	$ 110,503
Acquisition of equity investments in exchange for loan receivable and payable	$ 2,353	$ 26,035

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's operations are organized across two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The Liberty Power Group ("Liberty Power Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

1. Significant accounting policies

(a) Basis of preparation

The accompanying consolidated financial statements and notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosure required under Regulation S-X provided by the U.S. Securities and Exchange Commission.

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC, its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(m)). Intercompany transactions and balances have been eliminated. Interests in subsidiaries owned by third parties are included in non-controlling interests (note 1(r)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets which meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the stage of development (permitting, customer contracting, financing, construction) and the significance of the development risk with respect to achieving commercial operation. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred. When the set of activities does not represent a business, the transaction is accounted for as an asset acquisition and includes acquisitions costs.

Intangible assets acquired are recognized separately at fair value if they arise from contractual or other legal rights or are separable. Power sales contracts are amortized on a straight-line basis over the remaining term of the contract ranging from 6 to 25 years from the date of acquisition. Interconnection agreements are amortized on a straight-line basis over their estimated life of 40 years. Customer relationships are amortized on a straight-line basis over their estimated life of 40 years.

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

As at September 30 of each year, the Company assesses qualitative and quantitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge or credit against earnings for any remaining regulatory assets or liabilities. The impact could be material to the Company's reported financial condition and results of operations.

The electric, gas and water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"), the Regulator and National Association of Regulatory Utility Commissioners.

(e) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(f) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. As of December 31, 2016, restricted cash also included cash of U.S. $1,495,774 transfered to a paying agent for purposes of distribution to holders of common shares of The Empire District Electric Company and its subsidiaries ("Empire") on January 1, 2017 (note 3(a)). Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance sheet credit exposure related to its customers.

(h) Fuel and natural gas in storage

Fuel and natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents fuel, natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities and some generating facilities. Existing rate orders (note 7(d)) and other contracts allow the Company to pass through the cost of gas purchased directly to the customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the net realizable value of fuel and gas in storage does not fall below the cost to the Company.

(i) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and net realizable value. Through rate orders and the regulatory environment, capitalized construction jobs are recovered through rate base and repair and maintenance expenses are recovered through a cost of service calculation. Accordingly, the cost usually reflects the net realizable value.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management, together with the relevant authority, has authorized and committed to the funding of a project and it is probable that costs will be realized through the use of the asset or ultimate construction and operation of a facility. Project development costs for rate-regulated entities, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized either as property, plant and equipment or regulatory asset when it is determined that recovery of such costs through regulated revenue of the completed project is probable.

The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for funds used during construction ("AFUDC") for regulated property. Where possible, individual components are recorded and depreciated separately in the books and records of the Company. Plant and equipment under capital leases are initially recorded at cost determined as the present value of minimum lease payments.

AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835, Interest. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend, equity and other income on the consolidated statements of operations.

	2017	**2016**
Interest capitalized on non-regulated property	**$ 5,558**	$ 3,259
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,673**	1,167
Allowance for equity funds	**3,014**	2,774
Total	**$ 10,245**	$ 7,200

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Cost incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval. Maintenance and repair costs are expensed as incurred.

Investment tax credits and government grants related to capital expenditures are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 13(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Investment tax credits and government grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method with the exception of certain wind assets, as described below. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2017	**2016**	**2017**	**2016**
Generation	**3 - 60**	3 - 60	**33**	32
Distribution	**5 - 100**	5 - 100	**40**	41
Equipment	**5 - 50**	5 - 50	**13**	11

The Company uses the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Liberty Utilities Group are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operations in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(k) Commonly owned facilities

The Company owns undivided interests in three electric generating facilities with ownership interest ranging from 7.52% to 60% with a corresponding share of capacity and generation from the facility used to serve certain of its utility customers. The Company's investment in the undivided interest is recorded as plant in service and recovered through rate base. The Company's share of operating costs are recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

As at December 31, 2017, the Company's consolidated balance sheet includes $833,578 of cost of plant in service of and $225,156 of accumulated depreciation related to commonly owned facilities. Total expenditures for the year ended December 31, 2017 were $99,930.

(l) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(m) Variable interest entities

The Company performs analysis to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8).

1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

The Company has equity and notes receivable interests in two power generating facilities. APUC has determined that both entities are considered a VIE mainly based on total equity at risk not being sufficient to permit the legal entity to finance its activities without additional subordinated financial support. The key decisions that affect the generating facilities' economic performance relate to siting, permitting, technology, construction, operations and maintenance and financing. As APUC has both the power to direct the activities of the entities that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entities that could potentially be significant to the entity, the Company is considered the primary beneficiary.

Total net book value of generating assets and long-term debt of these facilities amounts to $84,550 (2016 - $87,189) and $35,914 (2016 - $40,398), respectively. The portion of long-term debt which has recourse to the Company is $3,900 (2016 - $6,900). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $22,743 (2016 - $29,132), operating expenses and amortization of $5,564 (2016 - $6,175) and interest expense of $3,573 (2016 - $4,064).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are accounted using the equity method. Equity-method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its investees in interest, dividend, equity and other income in the consolidated statements of operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. Interest from long-term investments is recorded as earned and collectability of both the interest and principal are reasonably assured.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

(o) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, other post-employment benefit ("OPEB"), supplemental retirement program ("SERP") plans for its various employee groups in Canada and the United States. Employer contributions to the defined contribution pension plans are expensed as employees render service. The Company recognizes the funded status of its defined benefit pension plans, OPEB and SERP plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

1. Significant accounting policies (continued)

(p) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, during construction or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation and amortization expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the obligation.

(q) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expense in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(r) Non-controlling interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the equity holders of APUC. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a consolidated subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLC") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLC and partnership's agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 19).

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Class A Equity Investors would receive if an equity investment entity were to liquidate all of its assets and distribute that cash to the investors based on the contractually defined liquidation priorities. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period is the Class A Equity Investors' share of the earnings or losses from the investment for that period. Due to certain mandatory liquidation provisions of the LLC and partnership agreements, this could result in a net loss to APUC's consolidated results in periods in which the Class A Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

1. Significant accounting policies (continued)

(r) Non-controlling interests (continued)

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(s) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Qualifying renewable energy projects receive renewable energy credits ("REC") and solar renewable energy credits ("SRECs") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The REC and SREC can be traded and the owner of the REC or SREC can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at the time of generation. Any REC's or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

Revenue related to utility electricity and natural gas sales and distribution are recorded when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for certain of the Company's regulated utilities is subject to revenue decoupling mechanisms approved by their respective regulators which require to charge approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(e)).

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rates and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue is recorded net of sales taxes.

1. Significant accounting policies (continued)

(t) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period.

Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

(u) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment (note 20). Investment tax credits for our rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Other income tax credits are treated as a reduction to income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(v) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost. Long-term debt and Series C preferred shares are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities and intercompany loans are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities and intercompany loans are amortized on a straight-line basis over the term of the respective instrument.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to some of its financial instruments used to manage its foreign currency risk exposure, interest risk and price risk exposure associated with sales of generated electricity.

1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized in OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount remaining in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecasted transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

The Company's electric distribution and thermal generation facilities enter into power and gas purchase contracts for load serving and generation requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(w) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

(x) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(y) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the measurement of deferred taxes and the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This update amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718), to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of this update in the first quarter of 2017 had no material impact on the Company's consolidated financial statements. The Company continues to record the stock-based compensation expense adjusted for estimated forfeitures.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments, to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, to clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, to simplify the subsequent measurement of inventory by replacing the current lower of cost and market test with a lower of cost and net realizable value test. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years . Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update.

The FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update. The Company expects to early adopt this update on January 1, 2018.

The FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting, to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The Company applies the guidance in this update for modifications subsequent to December 15, 2017.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, to improve the reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update will also only allow the service cost component to be eligible for capitalization when applicable. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this ASU, the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

The FASB issued ASU 2017-05 Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update clarifies the scope of the standard as well as provides additional guidance on partial sales of nonfinancial assets. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted however the update must be adopted at the same time as ASU 2014-09. No impact on the consolidated financial statements is expected from the adoption of this update.

The FASB issued ASU 2017-04 Business Combinations (Topic 350): Intangibles - Goodwill and Other (Topic 350) Simplifying the Test for Goodwill Impairment. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019.

The FASB issued ASU 2017-01 Business Combinations (Topic 805): Clarifying the Definition of a Business. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The amendments in the Update should be applied prospectively. The Company will follow the pronouncements of this Update after the effective date.

The FASB issued ASU 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The Company currently present changes in restricted cash as investing activities. The adoption of this standard will change the presentation of restricted cash on the consolidated statement of cash flows.

The FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes on these transactions until the asset has been sold to an outside party. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

The FASB issued ASU 2016-15 Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this Update.

The FASB issued ASU 2016-02, Leases (Topic 842) to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The FASB issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB also voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The standard is effective for fiscal years and interim periods beginning after December 15, 2018. Early adoption is permitted.

The Company is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. The Company held training sessions with the finance team and is currently in the process of creating an inventory of its lease contracts and analyzing the terms and conditions under the requirements of this new standard. The Company continues to monitor FASB amendments to ASC Topic 842.

The FASB issued ASU 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities to simplify the measurement, presentation, and disclosure of financial instruments. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The presentation of unrealized gains/ losses from the Company's available-for-sale investments will change on the consolidated statement of comprehensive income. Certain disclosures with regards to financial liabilities will change based on the updated requirements.

The FASB issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. The core principal of the accounting guidance is that an entity should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASC 606 is expected to require significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt.

The Company has completed its impact assessment. At this point, the Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company’s information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company intends to adopt the new revenue recognition standard using the modified retrospective method.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects

(a) Acquisition of Empire

On January 1, 2017, the Company completed the acquisition of Empire, a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately U.S. $2,414,000 for the acquisition of Empire consists of cash payment to Empire shareholders of U.S. $34.00 per common share and the assumption of approximately U.S. $855,000 of debt. The cash payment was funded with the acquisition facility for an amount of U.S. $1,336,440 (note 9(b)), proceeds received from the initial instalment of convertible debentures (note 14) and existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at January 1, 2017 based on their fair values, using the exchange rate on that date of U.S. $1.00 = CAD $1.3427.

Working capital	$ 55,441
Property, plant and equipment	2,764,441
Goodwill	1,010,273
Regulatory assets	318,130
Other assets	58,553
Long-term debt	(1,218,563)
Regulatory liabilities	(195,489)
Pension and other post-employment benefits	(105,005)
Deferred income tax liability, net	(562,397)
Other liabilities	(102,759)
Total net assets acquired	$ 2,022,625
Cash and cash equivalent	$ 2,338
Total net assets acquired, net of cash and cash equivalent	$ 2,020,287

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Empire's assets is 39 years.

The table below presents the consolidated pro forma revenue and net income for the year ended December 31, 2017 and 2016, assuming the acquisition of Empire had occurred on January 1, 2016. Pro forma net income includes the impact of fair value adjustments incorporated in the preliminary purchase price allocation above and adjustments necessary to reflect the financing costs as if the acquisition had been financed on January 1, 2016. However, non-recurring acquisition-related expenses are excluded from net income.

	Year Ended December 31	
	2017	**2016**
Revenues	**$ 1,977,809**	$ 1,908,340
Net earnings attributable to common shareholders	**$ 229,976**	$ 213,983

3. Business acquisitions and development projects (continued)

(a) Acquisition of Empire (continued)

This pro forma information does not purport to represent what the actual results of operations of the Company would have been had the acquisition occurred on this date nor does it purport to predict the results of operations for future periods.

(b) Investment in joint venture with Abengoa and investment in Atlantica

On November 1, 2017, APUC entered into an agreement to create a joint venture ("AAGES") with Seville, Spain-based Abengoa, S.A ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608,000, based on a price of U.S. $24.25 per ordinary share of Atlantica plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and other closing conditions.

(c) Great Bay Solar Project

On August 12, 2015, the Company acquired rights to develop a 75 MWac solar project in Somerset County, Maryland. The project consists of four separate sites: as of December 31, 2017, two sites had been fully synchronized with the power grid, one site partially placed in service, with the remaining portion of the facility expected to be placed in service in Q1 2018.

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). Approximately U.S. $59,000 of the permanent project financing will come from tax equity investors. Equity capital contribution of U.S. $42,750 was received in 2017 with the remaining expected to be received in early 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(d) Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving customers in northern New York state. The total purchase price for the transaction is U.S. $70,000, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

(e) Approval to acquire the Perris Water Distribution System

On August 10, 2017 the Company's board approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of U.S. $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission in Q1 2018 with approval expected in late 2018.

(f) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the "Luning Holdings") is owned by the Calpeco Electric System. The 50MWac solar generating facility is located in Mineral County, Nevada. During 2016, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $7,826 as of December 31, 2016 and U.S. $31,212 on February 17, 2017. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Luning Solar project. During a six-month period in year 2022, the tax investor has the right to withdraw from Luning Holdings and require the Company to redeem its remaining interests for cash. As a result, the Company accounts for this interest as "Redeemable non-controlling interest" outside of permanent equity on the consolidated balance sheets (note 19). Redemption is not considered probable as of December 31, 2017.

On February 15, 2017, as the Luning Solar Facility achieved commercial operation, Luning Holdings obtained control for a total purchase price of U.S. $110,856.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(f) Luning Solar Facility (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	198
Property, plant and equipment		145,045
Asset retirement obligation		(714)
Non-controlling interest (tax equity)		(50,548)
Total net assets acquired	$	93,981

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

(g) Bakersfield II Solar Facility

On December 14, 2016, the Company completed construction and placed in service a 10 MWac solar powered generating facility located adjacent to the Company's 20 MWac Bakersfield I Solar Facility in Kern County, California ("Bakersfield II Solar Facility"). Commercial operations as defined by the power purchase agreement was reached on January 11, 2017.

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield II Partnership"). The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $2,454 on November 29, 2016 and approximately U.S. $9,800 on February 28, 2017. With its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(h) Wind Turbine Components Purchase

In 2016, the Company purchased approximately $75,000 of wind turbine components that will qualify between 500 MW and 700 MW of new wind powered projects for the full U.S. $0.023/kWh renewable energy production tax credit under the safe harbor guidelines established by the U.S. Internal Revenue Service, provided that such projects are placed in service before the end of 2020.

(i) Acquisition of Park Water System

On January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. The total purchase price for the Park Water System is $353,077 (U.S. $249,540), net of the debt assumed of U.S. $91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed in the consolidated statements of operations. At the time of acquisition, Park Water System owned and operated three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. Those three utilities were named Park Water Company, Apple Valley Ranchos Water Co. and Mountain Water Company.

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On June 22, 2017, the city of Missoula took possession of Mountain Water's assets (note 23(a)).

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(i) Acquisition of Park Water System (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$ 2,045
Property, plant and equipment	345,254
Notes receivable	1,781
Goodwill	210,463
Regulatory assets	54,548
Other assets	185
Long-term debt	(146,727)
Regulatory liabilities	(3,758)
Pension and OPEB	(18,747)
Deferred income tax liability, net	(51,795)
Other liabilities	(40,172)
Total net assets acquired	$ 353,077

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions. Immaterial changes to the initial allocation were recorded during 2016.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Park Water System assets is 40 years.

The Park Water System contributed revenue of $91,817 (2016 - $96,695) and pre-tax net earnings of $17,620 (2016 - $25,374) to the Company’s consolidated financial results for the year ended December 31, 2017.

4. Accounts receivable

Accounts receivable as of December 31, 2017 include unbilled revenue of $98,214 (2016 - $57,822) from the Company’s regulated utilities. Accounts receivable as of December 31, 2017 are presented net of allowance for doubtful accounts of $6,968 (2016 - $7,064).

(in thousands of Canadian dollars, except as noted and per share amounts)

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2017

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,988,569	$ 494,912	$ 2,493,657
Distribution	5,247,499	483,345	4,764,154
Land	89,935	—	89,935
Equipment and other	143,158	51,026	92,132
Construction in progress			
Generation	263,418	—	263,418
Distribution	206,197	—	206,197
	$ 8,938,776	$ 1,029,283	$ 7,909,493

2016

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,613,267	$ 419,227	$ 2,194,040
Distribution	2,638,488	462,454	2,176,034
Land	60,868	—	60,868
Equipment and other	139,961	44,700	95,261
Construction in progress			
Generation	197,405	—	197,405
Distribution	166,338	—	166,338
	$ 5,816,327	$ 926,381	$ 4,889,946

Generation assets include cost of $142,789 (2016 - $142,246) and accumulated depreciation of $43,792 (2016 - $39,958) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,117 (2016 - $2,117).

Distribution assets include cost of $2,234,243 and accumulated depreciation of $587,202 related to regulated generation and transmission assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

For the year ended December 31, 2017, contributions received in aid of construction of $16,044 (2016 - $49,794) have been credited to the cost of the assets. The 2016 credit also includes Canadian renewable and conservation expense refundable tax credit for the St Damase wind facility in the amount of $14,086.

6. Intangible assets and goodwill

Intangible assets consist of the following:

2017

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 70,929	$ 46,263	$ 24,666
Customer relationships	33,619	11,085	22,534
Interconnection agreements	17,790	882	16,908
	$ 122,338	$ 58,230	$ 64,108

(in thousands of Canadian dollars, except as noted and per share amounts)

6. Intangible assets and goodwill (continued)

2016

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 72,207	$ 44,641	$ 27,566
Customer relationships	35,979	10,999	24,980
Interconnection agreements	13,000	557	12,443
	$ 121,186	$ 56,197	$ 64,989

Estimated amortization expense for intangible assets for the next year is $3,540, $3,390 in year two, $3,380 in year three, $3,040 in year four and $2,720 in year five.

All goodwill pertains to the Liberty Utilities Group. Changes in goodwill are as follows:

Balance, January 1, 2016	$ 110,493
Business acquisitions	210,463
Foreign exchange	(14,315)
Balance, December 31, 2016	$ 306,641
Business acquisitions (note 3(a))	1,010,273
Divestiture of operating entity (note 23(a))	(35,107)
Foreign exchange	(85,573)
Balance, December 31, 2017	$ 1,196,234

7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire also provides regulated water utility distribution services to three towns in Missouri. The Empire District Gas Company, a wholly owned subsidiary, is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period. The following regulatory proceedings were recently completed:

Utility	State	Regulatory Proceeding Type	Annual Revenue Increase U.S. $'000	Effective Date
EnergyNorth Gas System	New Hampshire	GRC	$6,750	Temporary increase effective July 1, 2017
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$6,105	July 1, 2016
Calpeco Electric System	California	Post-Test Year Adjustment Mechanism	$2,175	January 1, 2018
New England Gas System	Massachusetts	GRC	$8,300	U.S. $7,800 effective March 1, 2016 U.S. $500 effective March 1, 2017
New England Gas System	Massachusetts	Gas System Enhancement Plan	$2,928	May 1, 2017
Midstates Gas System	Illinois	GRC	$2,200	June 7, 2017
Peach State Gas System	Georgia	GRAM	$2,725	March 1, 2016
Bella Vista Water System Rio Rico Water/ Sewer System	Arizona	GRC	$1,935	November 1, 2016
CalPeco Electric System	California	GRC	$8,318	January 1, 2016
Various			$3,551	2016, 2017 & 2018

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	2017	2016
Regulatory assets		
Environmental remediation (a)	$ **103,761**	$ 104,160
Pension and post-employment benefits (b)	**132,615**	75,527
Debt premium (c)	**72,016**	25,173
Fuel and commodity costs adjustment (d)	**43,311**	6,990
Rate adjustment mechanism (e)	**44,523**	40,602
Clean Energy and other customer programs (f)	**25,820**	2,106
Deferred construction costs (g)	**17,994**	—
Asset retirement (h)	**20,172**	2,113
Income taxes (i)	**45,847**	10,182
Rate case costs (j)	**11,660**	8,572
Other	**33,415**	16,539
Total regulatory assets	$ **551,134**	$ 291,964
Less current regulatory assets	**(83,508)**	(48,440)
Non-current regulatory assets	$ **467,626**	$ 243,524
Regulatory liabilities		
Income taxes (i)	$ **402,868**	$ 1,501
Cost of removal (k)	**231,064**	110,330
Rate-base offset (l)	**16,577**	20,946
Fuel and commodity costs adjustment (d)	**29,535**	34,012
Deferred compensation received in relation to lost production (m)	**11,789**	—
Deferred construction costs - fuel related (g)	**9,306**	—
Pension and post-employment benefits (b)	**12,648**	5,481
Other	**11,269**	10,464
Total regulatory liabilities	$ **725,056**	$ 182,734
Less current regulatory liabilities	**(47,278)**	(47,769)
Non-current regulatory liabilities	$ **677,778**	$ 134,965

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 13(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of U.S. $21,626 relates to an acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order to be received on completion of the next general rate case. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation Non-retirement Post-employment Benefits and ASC 715 Compensation Retirement Benefits before the transfer to regulatory asset occurred. The pension and post-employments benefits liability is related to tracking accounts pertaining primarily to Park Water Company. The amounts recorded in these accounts occur when actual expenses have been less than adopted and refunds are expected to occur in future periods.

7. Regulatory matters (continued)

(c) Debt premium

Debt premium on acquired debt is recovered as a component of the weighted average cost of debt.

(d) Fuel and commodity costs adjustment

The revenue from the utilities includes a component which is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25(b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System and New England Gas Systems are subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but to be collected over a period not exceeding 24 months are accrued upon approval of the Final Order.

(f) Clean Energy and other customer programs

The regulatory asset for Clean Energy and customer programs includes initiatives related to solar rebate applications processed and resulting rebate-related costs. The amount also includes other energy efficiency programs.

(g) Deferred construction costs

Deferred construction costs reflects deferred construction costs and fuel related costs of specific generating facilities of Empire. These amounts are being recovered over the life of the plants.

(h) Asset retirement

The costs of retirement of assets are expected to be recovered through rates as well as the on-going liability accretion and asset depreciation expense.

(i) Income taxes

The income taxes regulatory assets and liabilities represent income taxes recoverable through future revenues required to fund flow-through deferred income tax liabilities and amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates.

The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $411,409.

(j) Rate case costs

The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(k) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(l) Rate-base offset

The regulators imposed a rate-base offset that will reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of 10-16 years.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

(m) Deferred compensation received in relation to lost production

The regulatory liability for deferred compensation received from lost production represents Empire's refund from Southwest Power Administration for lost revenues at one of its generating facilities. These costs are being amortized over the period approved by state regulators.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company generally earns carrying charges on the regulatory balances related to commodity cost adjustment, retroactive rate adjustments and rate case costs.

8. Long-term investments

Long-term investments consist of the following:

	2017	2016
Equity-method investees		
Red Lily I Wind Facility (a)	**$ 22,799**	$ 23,504
Deerfield Wind Project (b)	**—**	34,727
Amherst Island Wind Project (c)	**11,191**	558
Other	**6,489**	5,630
	$ 40,479	$ 64,419
Notes receivable		
Development loans (d)	**$ 37,710**	$ 32,125
Other	**4,163**	6,058
	41,873	38,183
Available-for-sale investment	**—**	169
Other investments	**2,115**	2,662
Total long-term investments	**$ 84,467**	$ 105,433

(a) Red Lily I Wind Facility

Up to April 12, 2016, the Red Lily I Partnership (the "Partnership") was 100% owned by an independent investor. APUC provided operation and supervision services to the Red Lily I project ("Red Lily I Wind Facility"), a 26.4 MW wind energy facility located in southeastern Saskatchewan. The Company's investment in the Red Lily I Wind Facility up to that date was in the form of subordinated debt facilities of the Partnership.

Effective April 12, 2016, the Company exercised its option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loans. The amount by which the carrying value of the Company's investment exceeds the Company's proportionate share of the Partnership's net assets is not material.

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of Red Lily I require unanimous consent. As such, APUC is deemed, under U.S. GAAP, to not have control over the Partnership. As APUC exercises significant influence over operating and financial policies of Red Lily I, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $2,776 (2016 - $1,288) to the Company's consolidated financial results for the year ended December 31, 2017.

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(b) Deerfield Wind Project

On October 19, 2015, the Company acquired a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan. On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo and obtained control of the facility.

Upon acquisition of the initial 50% equity interest of Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S. $262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S. $19,891 to the capital of Deerfield SponsorCo. Construction was completed during the first quarter of 2017 and sale of power to the utility under the power purchase agreement started on February 21, 2017. The interest capitalized during the year ended December 31, 2017 to the investment while the Deerfield Wind Project was under construction amounts to $nil (2016 - $6,072).

On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo for U.S. $21,585 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting which requires that the fair value of assets acquired and liabilities assumed in the subsidiary be recognized on the consolidated balance sheet as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of $nil was recorded on acquisition.

On May 10, 2017, tax equity funding of U.S. $166,595 was received.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working Capital	$	(14,551)
Property, plant and equipment		442,086
Construction loan		(352,666)
Asset retirement obligation		(2,816)
Deferred revenue		(1,556)
Deferred tax liability		(1,979)
Net assets acquired	$	68,518
Cash and cash equivalent	$	4,183
Net assets acquired, net of cash and cash equivalent	$	64,335

(c) Amherst Island Wind Project

Windlectric Inc. ("Windlectric") owns a 75 MW construction-stage wind development project ("Amherst Island Wind Project") in the province of Ontario. On December 20, 2016, Windlectric, a wholly owned subsidiary of the Company at the time, issued fifty percent of its common shares for $50 to a third party and as a result is no longer controlled by APUC. The Company holds an option to acquire the remaining common shares at a fixed price any time prior to January 15, 2019.

Windlectric is considered a VIE namely due to the low level of equity at risk at this point. The Company is not considered the primary beneficiary of Windlectric as the two shareholders have joint control and all decisions must be unanimous. As such, on the transaction date, the Company deconsolidated the assets and liabilities of Windlectric and recorded its retained non-controlling investment in equity and notes receivable and payable at fair value. A net gain of nil was recorded on deconsolidation. The Company is accounting for its investment in the joint venture under the equity method. The interest capitalized during the year ended December 31, 2017 to the investment while the Amherst Island Wind Project is under construction amounts to $1,447 (2016 - $491). As at December 31, 2017, the third-party construction debt of the joint venture was $133,765.

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(c) Amherst Island Wind Project (continued)

As of December 31, 2017, the Company's maximum exposure to loss of $289,374 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(d).

(d) Development loans

The Company entered into committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the equity investees' wind projects.

As at December 31, 2017, the Company has a loan and credit support facility with Windlectric of $37,710 (2016 - $29,723). The loan to Windlectric bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2019. The letters of credit are charged an annual fee of 2% on their stated amount. As of December 31, 2017, the following credit support was issued by the Company on behalf of Windlectric: $72,068 letters of credit and guarantees of obligations to the utilities under the PPAs; a guarantee of the obligations under the wind turbine, transmission line, transformer, and other supply agreements; a guarantee of the obligations under the engineering, procurement, and construction management agreements. The initial value of the guarantee obligations is recognized under other long-term liabilities and was valued at $2,449 using a probability weighted discounted cash flow (level 3).

Following acquisition of control of Deerfield SponsorCo (note 8(b)) and Odell SponsorCo LLC (note 8(e)(i)), amounts advanced to the wind project are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income from the date of acquisition.

No interest revenue is accrued on the loans due to insufficient collateral in the Joint Ventures.

(e) 2016 transactions

i. Odell Wind Facility

Up to September 15, 2016, the Company held a 50% equity interest in Odell SponsorCo LLC, which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Facility") in the state of Minnesota.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S. $26,500 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting, which requires, that the fair value of assets acquired, liabilities assumed and non-controlling interest in the subsidiary, be recognized on the consolidated balance sheets as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of nil was recorded on acquisition.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	11,836
Property, plant and equipment		469,222
Asset retirement obligation		(4,812)
Deferred tax liability		(4,273)
Non-controlling interest (tax equity investors)		(237,156)
Net assets	$	234,817

ii. Natural gas pipeline developments

During 2016, APUC wrote off an amount of $6,367 representing the total value of its equity interest in the natural gas development projects as both projects have been canceled by the developer.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity	Par value	2017	2016
Senior Unsecured Revolving Credit Facilities (a)	—	2018-2022	N/A	**$ 65,017**	$ 242,947
Senior Unsecured Bank Credit Facilities (b)	—	2018-2019	N/A	**169,343**	2,140,122
Commercial Paper (c)		2019	N/A	**6,994**	—
Canadian Dollar Borrowings					
Senior Unsecured Notes (d)	4.61%	2018-2027	$ 785,669	**781,833**	487,389
Senior Secured Project Notes	10.27%	2020-2027	$ 33,568	**33,507**	35,600
U.S. Dollar Borrowings					
Senior Unsecured Notes (e)	4.09%	2020-2047	US$1,225,000	**1,527,726**	700,600
Senior Unsecured Utility Notes (f)	5.98%	2020-2035	US$ 227,000	**309,309**	174,206
Senior Secured Utility Bonds (g)	4.95%	2018-2044	US$ 752,500	**969,567**	132,551
				$ 3,863,296	$ 3,913,415
Less: current portion				**(15,511)**	(10,075)
				$ 3,847,785	$ 3,903,340

Long-term debt issued at a subsidiary level (project notes or utility bonds) relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt issued at a subsidiary level whether or not collateralized have certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Short-term obligations of $264,214 for which the maturity has been extended beyond 12 months subsequent to the end of the year or that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

Recent financing activities:

(a) Senior unsecured revolving credit facilities

On September 20, 2017, the Company amended the terms of its $65,000 senior unsecured revolving bank credit facility to increase the commitments to $165,000 and extend the maturity from November 19, 2017 to November 19, 2018.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200,000 senior unsecured revolving credit facility ("Liberty Credit Facility") and a U.S. $200,000 revolving credit facility at Empire ("Empire Credit Facility") assumed in connection with the acquisition of Empire (note 3(a)). Subsequent to year-end on February 23, 2018, the Liberty Utilities Group' increased commitments under the Liberty Credit Facility to U.S. $500,000 and extended the maturity to February 23, 2023. Concurrent with the amendment to the Liberty Credit Facility, the Liberty Utilities Group closed the Empire Credit Facility.

On October 6, 2017, the Liberty Power Group amended the terms of its $350,000 senior unsecured revolving bank credit facility to increase the commitments to U.S. $500,000 and extended the maturity from July 31, 2019 to October 6, 2022. On October 6, 2017, the St. Damase Wind Facility entered into a $4,000 committed revolving credit facility. The facility matures on October 6, 2020 and is guaranteed by the Liberty Power Group. The facility replaces borrowings that were previously drawn under the Liberty Power Group's senior unsecured revolving credit facility. As at December 31, 2017, $3,900 had been drawn on the facility.

9. Long-term debt (continued)

(a) Senior unsecured revolving credit facilities (continued)

Liberty Power had a $150,000 bilateral revolving credit facility with a maturity date of August 19, 2018. Concurrent with the expansion of the Liberty Power Credit Facility, the Liberty Power Group closed the bilateral credit facility on October 6, 2017.

On December 31, 2017, the Liberty Power Group had an extendible one-year letter of credit facility agreement. The facility provides for issuances of letters of credit up to a maximum of $50,000 and U.S. $30,000. Subsequent to year-end, on February 16, 2018, the Liberty Power Group's increased availability under its revolving letter of credit facility to U.S. $200,000 and extended the maturity to January 31, 2021.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $4,250 of debt outstanding under its revolving credit facilities. Shortly after the closing of the acquisition, the Park Water System repaid and closed the revolving credit facilities.

(b) Senior unsecured bank credit facilities

On December 21, 2017, the Company entered into a U.S. $600,000 term credit facility with two Canadian banks maturing on December 21, 2018. On March 7, 2018 the company drew U.S. $600,000 under this facility.

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. $1,336,440 from the Acquisition Facility it obtained in 2016. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. The total amount of cash held by the paying agent of U.S. $1,495,774 is comprised of this Acquisition Facility draw of U.S. $1,336,440 and cash proceeds received from the initial instalment of convertible debentures (note 14) and is presented as restricted cash on the consolidated balance sheets. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 14) and the senior notes financing on March 24, 2017 (note 9(d)), the Company fully repaid the Acquisition Facility.

On January 4, 2016, the Company entered into a U.S. $235,000 term credit facility with two U.S. banks. On March 24, 2017, the Company repaid U.S. $100,000 of borrowings under the Corporate Term Credit Facility with proceeds from the closing of the U.S. $750,000 senior unsecured notes (notes 9(e)). In October 2017, the Company extended the maturity on its Corporate Term Credit Facility to July 5, 2019.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $22,500 of debt outstanding under a non-revolving term credit facility. In June 2017, this debt was fully repaid and closed.

(c) Commercial Paper

In connection with the acquisition of Empire (note 3(a)), the Company assumed a short-term U.S. $150,000 commercial paper program.

(d) Canadian dollar senior unsecured notes

On January 17, 2017, the Liberty Power Group issued $300,000 senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount.

In September 2017, the Company acquired an investment in an equity-investee in exchange for a note payable to the other partner of $669. Repayment of the note is expected in 2019.

(e) U.S. dollar senior unsecured notes

On March 24, 2017, the Liberty Utilities Group 's debt financing entity issued U.S. $750,000 senior unsecured notes in six tranches. The proceeds were applied to repay the Acquisition Facility (note 9(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of this financing, the Liberty Utilities Group had entered into forward contracts to lock in the underlying U.S. Treasury interest rates. Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group will be approximately 3.6%.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term debt (continued)

(f) U.S. dollar senior unsecured utility notes

On February 8, 2017, the U.S.$707 Bella Vista Water unsecured notes were fully repaid.

On January 1, 2017, in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $102,000 in unsecured utility notes. The notes consist of two tranches, with maturities in 2033 and 2035 with coupons at 6.7% and 5.8%.

(g) U.S. dollar senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $733,000 in secured utility notes. The bonds are secured by a first mortgage indenture and consist of ten tranches with maturities ranging between 2018 and 2044 with coupons ranging from 3.58% to 6.82%.

In June 2017, outstanding bonds payable for the Park Water systems in the amount of U.S. $63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 23(a). The Company had assumed the U.S. $65,000 of debt outstanding in connection with the acquisition of Park Water in 2016 (note 3(i)).

(h) U.S. dollar senior secured project notes

On March 14, 2017, in connection with the acquisition of Deerfield SponsorCo (note 8(b)), the Company assumed U.S. $262,219 in construction loan. The loans bear interest at an annual rate of 2.33% on any outstanding principal amount. On May 10, 2017, the construction loan was repaid from proceeds received from tax equity (note 8(b)) and cash contributions from APUC.

As of December 31, 2017, the Company had accrued $41,479 in interest expense (2016 - $27,225). Interest expense on the long-term debt in 2017 was $185,339 (2016 - $87,143).

Principal payments due in the next five years and thereafter are as follows:

2018	2019	2020	2021	2022	Thereafter	Total
$ 279,724	$ 179,107	$ 391,025	$ 152,626	$ 492,343	$ 2,331,327	$ 3,826,152

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to substantially all of its employees. The Company's contributions for 2017 were $9,387 (2016 - $5,223).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain existing plans. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 331,934**	$ 269,382	**$ 83,097**	$ 76,565
Projected benefit obligation assumed from business combination	**344,383**	63,811	**131,263**	9,749
Modifications to pension plan	**—**	(2,754)	**—**	(1,235)
Service cost	**17,869**	8,435	**6,280**	2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Actuarial (gain) loss	**49,785**	6,773	**13,321**	(2,870)
Contributions from retirees	**—**	—	**2,364**	547
Gain on curtailment	**(1,129)**	—	**(6)**	—
Benefits paid	**(64,605)**	(15,845)	**(8,092)**	(3,230)
Gain on foreign exchange	**(48,546)**	(10,897)	**(14,834)**	(2,870)
Projected benefit obligation, end of year	**$ 657,037**	$ 331,934	**$ 222,014**	$ 83,097
Change in plan assets				
Fair value of plan assets, beginning of year	**236,369**	176,171	**29,139**	18,149
Plan assets acquired in business combination	**247,741**	44,258	**122,900**	10,563
Actual return on plan assets	**82,096**	17,221	**25,612**	1,854
Employer contributions	**38,833**	21,776	**2,683**	2,317
Benefits paid	**(64,605)**	(15,845)	**(5,901)**	(2,683)
Loss on foreign exchange	**(33,686)**	(7,212)	**(10,737)**	(1,061)
Fair value of plan assets, end of year	**$ 506,748**	$ 236,369	**$ 163,696**	$ 29,139
Unfunded status	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)
Amounts recognized in the consolidated balance sheets consists of:				
Non-current assets	**—**	—	**4,938**	—
Current liabilities	**(1,080)**	(436)	**(1,471)**	(1,242)
Non-current liabilities	**(149,209)**	(95,129)	**(61,785)**	(52,716)
Net amount recognized	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)

The accumulated benefit obligation for the pension plans was $614,840 and $317,025 as of December 31, 2017 and 2016, respectively.

On June 22, 2017, all Mountain Water employees were terminated as a result of the condemnation of the Mountain Water assets to the city of Missoula (note 23(a)). The pension and OPEB obligations of these employees remain with the Company. The assets and projected benefit obligations of the plans were revalued at June 30, 2017 and resulted in an actuarial gain of U.S. $2,354 recorded in other comprehensive income and a curtailment gain of U.S. $853 recorded against the loss on long-lived assets.

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain of the existing plans. The plan amendments resulted in a decrease to the projected benefit obligation of U.S. $2,217 which is recorded as a prior service credit in OCI. In conjunction with the plan amendments, the assets and projected benefit obligations of amended plans were revalued at the closest month-end date which resulted in an actuarial loss of U.S. $8,204 recorded in OCI.

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2016	$ 29,461	$ (4,970)	$ (2,338)	$ —
Additions to AOCI	4,479	(2,754)	(3,242)	(1,235)
Amortization in current period	(1,965)	765	(80)	347
Balance at December 31, 2016	$ 31,975	$ (6,959)	$ (5,660)	$ (888)
Additions to AOCI	(3,716)	—	(4,276)	—
Reclassification to regulatory accounts	1,584	—	4,902	—
Amortization in current period	(1,290)	868	321	365
Balance at December 31, 2017	$ 28,553	$ (6,091)	$ (4,713)	$ (523)
Expected amortization in 2018	$ (451)	$ 781	$ 214	$ 328

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	2016	2017	2016
Discount rate	**4.01%**	4.16%	**4.12%**	4.23%
Expected return on assets	**7.01%**	6.41%	**3.88%**	5.50%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.50%
Age 65 and after			**6.25%**	6.50%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2023**	2023

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

Weighted average assumptions used to determine net benefit obligation for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Discount rate	**3.43%**	3.95%	**3.60%**	4.04%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.25%
Age 65 and after			**6.25%**	6.25%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2024**	2023

The mortality assumption for December 31, 2017 was updated to the projected generationally scale MP-2017, adjusted to reflect the ultimate improvement rates in the 2017 Social Security Administration intermediate assumptions.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2017 is as follows. The effects on total service and interest cost of a one percent change in HCCTR excludes the effects of Empire.

	2017
Effect of a 1 percentage point increase in the HCCTR on:	
Year-end benefit obligation	$ 38,047
Total service and interest cost	959
Effect of a 1 percentage point decrease in the HCCTR on:	
Year-end benefit obligation	$ (30,057)
Total service and interest cost	(765)

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(c) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Service cost	**$ 17,869**	$ 8,435	**$ 6,280**	$ 2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Expected return on plan assets	**(32,244)**	(14,854)	**(8,312)**	(1,265)
Amortization of net actuarial loss (gain)	**1,480**	1,965	**(299)**	80
Amortization of prior service credits	**(808)**	(765)	**(339)**	(347)
Gain on curtailments and settlements	**(1,394)**	—	**(6)**	—
Amortization of regulatory assets/ liability	**15,179**	4,698	**507**	1,471
Net benefit cost	**$ 27,428**	$ 12,508	**$ 6,452**	$ 6,380

(d) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	70%	49% - 79%
Debt securities	30%	21% - 51%
Other	—%	—%

The fair values of investments as of December 31, 2017, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	505,219	72%
Debt securities	164,281	27%
Other	945	—%

As of December 31, 2017, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $26,686 to its pension plans and $4,898 to its post-employment benefit plans in 2018.

The expected benefit payments over the next ten years are as follows:

	2017	2018	2019	2020	2021	2022-2026
Pension plan	$ 43,445	$ 39,037	$ 40,132	$ 45,060	$ 45,108	$ 236,821
OPEB	7,353	7,989	8,845	9,425	10,093	58,844

(in thousands of Canadian dollars, except as noted and per share amounts)

11. Mandatorily redeemable Series C preferred shares

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule indexed in proportion to the increase in CPI over the term of the shares. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

As these shares are mandatorily redeemable for cash, they are classified as liabilities in the consolidated financial statements. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:	
2018	$ 1,068
2019	1,282
2020	1,344
2021	1,364
2022	1,390
Thereafter to 2031	15,761
Redemption amount	5,340
	27,549
Less amounts representing interest	(9,085)
	18,464
Less current portion	(1,068)
	$ 17,396

12. Other assets

Other assets consist of the following:

	2017	2016
Income tax receivable	**$ 7,485**	$ 2,951
Deferred financing costs	**4,448**	10,198
Other	**18,633**	6,136
	30,566	19,285
Less current portion	**(8,919)**	(2,951)
	$ 21,647	$ 16,334

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	2017	2016
Advances in aid of construction (a)	**$ 78,636**	$ 105,191
Environmental remediation obligation (b)	**68,147**	63,378
Asset retirement obligations (c)	**55,406**	24,822
Customer deposits (d)	**35,790**	14,881
Unamortized investment tax credits (e)	**22,379**	—
Deferred credits (f)	**26,555**	44,544
Other	**55,779**	22,790
	342,692	275,606
Less current portion	**(57,586)**	(43,157)
	$ 285,106	$ 232,449

(a) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 5 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2017, $13,626 (2016 - $23,986) was transferred from advances in aid of construction to contributions in aid of construction.

(b) Environmental remediation obligation

A number of the Company's regulated utilities were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $71,873 (2016 - $76,853) which at discount rates ranging from 2.2% to 2.5% represents the recorded accrual of $68,147 as of December 31, 2017 (2016 - $63,378). Approximately $25,186 is expected to be incurred over the next two years with the balance of cash flows to be incurred over the following 28 years.

Changes in the environmental remediation obligation are as follows:

	2017	2016
Opening Balance	**$ 63,378**	$ 71,529
Remediation activities	**(2,026)**	(1,389)
Accretion	**1,447**	2,464
Changes in cash flow estimates	**2,135**	2,088
Revision in assumptions	**7,686**	(9,101)
Foreign exchange rate adjustment	**(4,473)**	(2,213)
Closing Balance	**$ 68,147**	$ 63,378

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2017, the Company has reflected a regulatory asset of $103,761 (2016 - $104,160) for the MGP and related sites (note 7(a)).

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and deferred credits (continued)

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and Polychlorinated Biphenyls "PCB" contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; (iv) remove certain river water intake structures and equipment; (v) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities. During the year, APUC assumed asset retirement obligations in connection with the acquisitions of Empire (note 3(a)) and Deerfield SponsorCo (note 8(b)) of $31,717 and $2,816, respectively, recorded additional asset retirement obligations for renewable generation facilities being constructed of $2,604 (2016 - $393), changes in estimates of $1,476 (2016 - $1,022), accretion expense of $2,551 (2016 - $1,055) and settlements of $5,418 (2016 - $nil).

As the cost of retirement of utility assets are expected to be recovered through rates, a corresponding regulatory asset is recorded, as well as the on-going liability accretion and asset depreciation expense (note 7(h)).

(d) Customer deposits

Customer deposits result from the Company's obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(e) Unamortized investment tax credits

The unamortized investment tax credits were assumed in connection with the acquisition of Empire. The investment tax credits are associated with an investment made in a generating station. The credits are being amortized over the life of the generating station.

(f) Deferred credits

Deferred credits include unresolved contingent consideration related to prior acquisitions which are expected to be paid and deferred tax credits (note 20).

14. Convertible Unsecured Subordinated Debentures

Maturity date		March 31, 2026
Interest rate		5.00%
Conversion price per share	$	10.60
Receipt of Initial instalment, net of deferred financing costs	$	357,694
Amortization of deferred financing costs		925
Carrying value at December 31, 2016		358,619
Receipt of Final instalment, net of deferred financing costs		743,881
Amortization of deferred financing costs		1,134
Conversion to common shares	$	(1,102,416)
Carrying value at December 31, 2017	$	1,218
Face value at December 31, 2017	$	1,277

On March 1, 2016, the Company completed the sale of $1,150,000 aggregate principal amount of 5.0% convertible debentures.

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount of debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the "Final Instalment") was received on February 2, 2017 ("Final Instalment Date") following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial and final instalments, net of financing costs were $357,694 and $743,881, respectively.

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Convertible Unsecured Subordinated Debentures (continued)

The convertible debentures mature on March 31, 2026 and bore interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate is 0%. The interest expense recorded for the year ended December 31, 2017 is $9,373 (2016 - $48,205). As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017.

The debentures are convertible into up to 108,490,566 common shares. As at December 31, 2017, a total of 108,370,081 common shares of the company were issued (Note 15), representing conversion into common shares of 99.9% of the convertible debentures.

After the Final Instalment Date, any debentures not converted into common shares may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

15. Shareholders' capital

(a) Common shares

Number of common shares:

	2017	2016
Common shares, beginning of year	**274,087,018**	255,869,419
Public offering (i) and subscription receipts (ii)	**43,470,000**	12,938,457
Conversion of convertible debentures (note 14)	**108,370,081**	—
Dividend reinvestment plan (iii)	**3,905,848**	2,322,618
Exercise of share-based awards (c)	**1,932,988**	2,956,524
Common shares, end of year	**431,765,935**	274,087,018

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC, subject to the rights of any shares having priority over the common shares.

The Company has a shareholders' rights plan (the "Rights Plan") which expires in 2019. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

On November 10, 2017, APUC issued 43,470,000 common shares at $13.25 per share pursuant to a public offering for proceeds of $576,000 before issuance costs of $24,342 or $17,895 net of taxes.

(ii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 from the issuance to Emera Inc. ("Emera") of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment (note 8(c)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(a) Common shares (continued)

(ii) Subscription receipts (continued)

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(i)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

(iii) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 1,063,572 common shares under the dividend reinvestment plan.

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2017 and 2016:

Preferred shares	Number of shares	Price per share	Carrying amount
Series A	**4,800,000**	**$ 25**	**$ 116,546**
Series D	**4,000,000**	**$ 25**	**97,259**
			$ 213,805

The holders of Series A and Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of $1.125 and $1.25 per share, respectively, for each year up to, but excluding December 31, 2018 and March 31, 2019, respectively. The Series A and Series D dividend rate will reset on those dates and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94% and 3.28%, respectively. The Series A and Series D preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter.

The holders of Series A and Series D preferred shares have the right to convert their shares into cumulative floating rate preferred shares, Series B and Series E, respectively, subject to certain conditions, on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter. The Series B and Series E preferred shares will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94% and 3.28%, respectively. The holders of Series B and Series E preferred shares will have the right to convert their shares back into Series A and Series D preferred shares on December 31, 2018 and March 31, 2019, respectively and every fifth year thereafter. The Series A, Series B, Series D and Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

The Company has 100 redeemable Series C preferred shares issued and outstanding. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets as they are mandatorily redeemable for cash (note 11).

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2017, APUC recorded $10,804 (2016 - $5,675) in total share-based compensation expense detailed as follows:

		2017		2016
Share options	**$**	**3,990**	$	3,006
Directors deferred share units		**771**		683
Employee share purchase		**568**		238
Performance share units		**5,475**		1,748
Total share-based compensation	**$**	**10,804**	$	5,675

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2017, total unrecognized compensation costs related to non-vested options and PSUs were $2,796 and $8,471, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 8% of the number of shares outstanding at the time the options are granted.

The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money Amount" being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

In the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board ("Compensation Committee")) in accordance with the terms of the Company's clawback policy.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was based on experience to-date. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

The following assumptions were used in determining the fair value of share options granted:

	2017	2016
Risk-free interest rate	**1.4%**	**0.9%**
Expected volatility	**25%**	**23%**
Expected dividend yield	**4.3%**	**4.5%**
Expected life	**5.50 years**	**5.50 years**
Weighted average grant date fair value per option	**$ 1.45**	**$ 1.26**

Share option activity during the years is as follows:

	Number of awards	Weighted average exercise price	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2016	7,164,652	$ 6.92	4.74	$ 28,561
Granted	2,596,025	10.85	8.00	—
Exercised	(3,715,663)	5.25	2.06	20,790
Balance at December 31, 2016	6,045,014	$ 9.64	6.27	$ 10,595
Granted	2,328,343	12.82	8.00	
Exercised	(1,634,501)	7.81	3.76	7,696
Balance at December 31, 2017	6,738,856	$ 11.18	6.32	$ 19,380
Exercisable at December 31, 2017	2,448,689	$ 10.03	5.61	$ 9,473,719

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match (a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Common shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2017, a total of 283,523 common shares (2016 - 144,264) were issued to employees under the ESPP.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2017, 293,906 (2016 - 224,663) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU Plan shall not exceed 1,000,000 common shares.

(iv) Performance share units

The Company offers a PSU plan to its employees as part of the Company's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2.0% to 237% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU Plan shall not exceed 7,000,000 common shares.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the balance sheet date. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date.

A summary of the PSUs follows:

	Number of awards	Weighted average grant-date fair value	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2016	564,116	$ 7.59	1.63	$ 6,155
Granted, including dividends	219,315	11.62	2.00	—
Exercised	(181,875)	8.29	—	2,115
Forfeited	(22,568)	9.64	—	—
Balance at December 31, 2016	578,988	$ 9.82	1.74	$ 6,595
Granted, including dividends	811,974	13.54	2.00	—
Exercised	(374,973)	8.33	—	4,394
Forfeited	(60,961)	12.61	—	—
Balance at December 31, 2017	955,028	$ 12.30	1.84	$ 13,428
Exercisable at December 31, 2017	172,031	$ 9.75	—	$ 2,423

(in thousands of Canadian dollars, except as noted and per share amounts)

16. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2016	$ 261,357	$ 39,329	$ (72)	$ (13,877)	$ 286,737
OCI (loss) before reclassifications	(61,029)	34,308	213	2,856	(23,652)
Amounts reclassified	—	(7,554)	—	(604)	(8,158)
Net current period OCI	(61,029)	26,754	213	2,252	(31,810)
Balance, December 31, 2016	$ 200,328	$ 66,083	$ 141	$ (11,625)	$ 254,927
OCI before reclassifications	(200,400)	8,714	—	838	(190,848)
Amounts reclassified	—	(6,805)	(141)	(313)	(7,259)
Net current period OCI	$(200,400)	$ 1,909	$ (141)	$ 525	$ (198,107)
Balance, December 31, 2017	$ (72)	$ 67,992	$ —	$ (11,100)	$ 56,820

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected administrative expenses.

17. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividend on its commons shares in U.S. dollars. Dividends declared in Canadian equivalent dollars during the year were as follows:

	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 242,509**	**$ 0.6084**	$ 149,158	$ 0.5452
Series A preferred shares	**$ 5,400**	**$ 1.1250**	$ 5,400	$ 1.1250
Series D preferred shares	**$ 5,000**	**$ 1.2500**	$ 5,000	$ 1.2500

18. Related party transactions

Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4,397 (2016 - U.S. $10,185). The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions amounts to U.S. $1,006 (2016 - U.S. $3,939). Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction. In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in Q2 2017 with final completion of the contract work in the fourth quarter. The total cost of the contract was $9,500. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $680 to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1,467 included in accruals in 2017 (2016 - U.S. $757) related to these transactions at the end of the year.

(in thousands of Canadian dollars, except as noted and per share amounts)

18. Related party transactions (continued)

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $5,969 (2016 - $3,313) during the year.

Trafalgar

In 2016, the Company received U.S. $10,083 in proceeds from the settlement of the Trafalgar matter, and paid U.S. $2,900 to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6,600 was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

19. Non-controlling interests and Redeemable non-controlling interest

Net loss attributable to non-controlling interests for the years ended December 31 consists of the following:

	2017	2016
HLBV and other adjustments attributable to:		
Non-controlling interest -Class A partnership units	**$ (52,020)**	$ (35,451)
Non-controlling interest -redeemable Class A partnership units	**(13,400)**	(4,952)
Other net earnings attributable to non-controlling interests	**3,172**	1,853
Net effect of non-controlling interests	**$ (62,248)**	$ (38,550)

The non-controlling Class A membership equity investors ("Class A partnership units") in the Company's U.S. wind power and solar power generating facilities are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(r).

The terms of the arrangement refer to the tax rate in effect when the benefits are delivered. As such, The U.S. federal corporate tax rate of 35% was used to calculate HLBV as at December 31, 2017. The reduced U.S. federal corporate tax rate of 21% and other certain measures discussed in note 20 will be used in the calculation of HLBV beginning in 2018.

Non-controlling interest

As of December 31, 2017, non-controlling interests of $756,007 (2016 - $562,358) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $754,932 (2016 - $561,308) and other non-controlling interests of $1,075 (2016 - $1,050). Contributions from new Class A partnership investors of U.S. $42,750 was received for the Great Bay Solar Facility in 2017 (note 3(c)); U.S. $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(g)); and, U.S. $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 8(b)).

(in thousands of Canadian dollars, except as noted and per share amounts)

19. Non-controlling interests and Redeemable non-controlling interest (continued)

Redeemable Non-controlling interest

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The redeemable non-controlling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method subsequent to initial recognition, however, if the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2017. Changes in redeemable non-controlling interest are as follows:

	2017	2016
Opening balance	**$ 29,434**	$ 25,751
Net loss attributable to redeemable non-controlling interest	**(13,400)**	(4,952)
Contributions from redeemable non-controlling interests (note 3(f))	**40,797**	10,171
Dividends declared and distributions to redeemable non-controlling interest	**(1,454)**	(590)
Foreign exchange	**(3,249)**	(946)
Closing balance	**$ 52,128**	$ 29,434

Contributions from new Class A partnership investors of U.S. $31,212 was received for the Luning Solar Facility on on February 17, 2017 (note 3(f)).

20. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2016 - 26.5%). The differences are as follows:

	2017	2016
Expected income tax expense at Canadian statutory rate	**$ 59,907**	$ 34,317
Increase (decrease) resulting from:		
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(27,671)**	(11,363)
Non-controlling interests share of income	**24,708**	13,973
Allowance for equity funds used during construction	**(1,029)**	(1,100)
Capital gain rate differential	**(919)**	(3,612)
Goodwill divestiture and permanent basis differences associated with Mountain Water condemnation	**7,059**	—
Non-deductible acquisition costs	**18,091**	1,996
Change in valuation allowance	**(1,304)**	2,841
Tax credits	**(8,162)**	(477)
Adjustment relating to prior periods	**(30)**	(711)
U.S. tax reform	**22,390**	—
Other	**2,154**	1,272
Income tax expense	**$ 95,194**	$ 37,136

On December 22, 2017, the US Tax Cuts and Jobs Act of 2017 (the Act) was signed into legislation. The Act includes a broad range of legislative changes including a reduction of the US federal corporate income tax rate from 35% to 21% effective January 1, 2018, limitations on the deductibility of interest and 100% expensing of qualified property. The Act provides an exemption to regulated utilities from the limitations on the deductibility of interest and also does not permit regulated utilities to immediately expense 100% of the cost of new investments in qualified property.

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

As a result of the Act being enacted during 2017, the Company is required to revalue its United States deferred income tax assets and liabilities based on the rates they are expected to reverse at in the future, which is generally 21% for U.S. federal tax purposes. The company was able to make reasonable estimates of the impact of the Act and has recorded provisional amounts for the remeasurement of deferred taxes. The Company has recognized a provisional charge to income tax expense of $22,390 in 2017 as a result of the revaluation of its U.S. non-regulated net deferred income tax assets. The Company has also reduced its regulated net deferred income tax liabilities by a provisional amount of $411,409 and recorded an equivalent increase to net regulatory liability since the benefit of lower U.S. taxes is probable of being returned to customers by order of the applicable regulator.

The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act.

For the years ended December 31, 2017 and 2016, earnings from continuing operations before income taxes consist of the following:

	2017	2016
Canadian operations	**$ (3,269)**	$ 29
U.S. operations	**229,309**	129,481
	$ 226,040	$ 129,510

Income tax expense (recovery) attributable to income (loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2017			
Canada	**$ 4,277**	**$ (18,390)**	**$ (14,113)**
United States	**5,631**	**103,676**	**109,307**
	$ 9,908	**$ 85,286**	**$ 95,194**
Year ended December 31, 2016			
Canada	$ 7,533	$ (10,501)	$ (2,968)
United States	928	39,176	40,104
	$ 8,461	$ 28,675	$ 37,136

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2017 and 2016 are presented below:

	2017	2016
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 412,327**	$ 459,436
Pension and OPEB	**54,744**	57,751
Acquisition-related costs	**2,008**	3,612
Environmental obligation	**18,570**	25,683
Reserves and other non-deductible costs	**38,453**	11,390
Regulatory liabilities	**193,942**	76,315
Other	**20,555**	14,374
Total deferred income tax assets	**740,599**	648,561
Less valuation allowance	**(15,486)**	(21,656)
Total deferred tax assets	**725,113**	626,905
Deferred tax liabilities:		
Property, plant and equipment	**(838,110)**	(562,124)
Intangible assets	**(8,067)**	(8,035)
Outside basis in partnership	**(157,463)**	(187,717)
Regulatory accounts	**(143,090)**	(108,506)
Financial derivatives	**(1,230)**	(17,649)
Other	**—**	(1,008)
Total deferred tax liabilities	**(1,147,960)**	(885,039)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)
Consolidated Balance Sheets Classification:		
Deferred tax assets	**$ 76,972**	$ 30,005
Deferred tax liabilities	**(499,819)**	$ (288,139)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)

The valuation allowance for deferred tax assets as at December 31, 2017 was $15,486 (2016 - $21,656). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

As of December 31, 2017, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforwards
2020 and onwards	$ 1,247,448

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of its subsidiaries. Deferred income taxes have not been provided on approximately $188,348 of undistributed earnings of certain foreign subsidiaries, as the Company has concluded that such earnings are indefinitely reinvested and should not give rise to additional tax liabilities. A determination of the amount of the unrecognized tax liability relating to the remittance of such undistributed earnings is not practicable.

(in thousands of Canadian dollars, except as noted and per share amounts)

21. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding (note 15 (a)). Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options. The convertible debentures (note 14) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

	2017	2016
Net earnings attributable to shareholders of APUC	**$ 193,094**	$ 130,924
Series A Preferred shares dividend	**5,400**	5,400
Series D Preferred shares dividend	**5,000**	5,000
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$ 182,694**	$ 120,524
Weighted average number of shares		
Basic	**382,323,434**	271,832,430
Effect of dilutive securities	**3,662,714**	2,244,602
Diluted	**385,986,148**	274,077,032

The shares potentially issuable as a result of 2,328,343 share options (2016 - 1,665,131) are excluded from this calculation as they are anti-dilutive.

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information

In connection with the acquisition of Empire on January 1, 2017, the Company aligned its management reporting under two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The two business units are the two segments of the Company.

The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these segments are reflected in the tables below. The comparative information for 2016 has been reclassified to conform with the composition of the reporting segments presented in the current year.

	Year ended December 31, 2017			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 300,173	$ 1,677,636	$ —	$ 1,977,809
Fuel, power and water purchased	25,384	485,016	—	510,400
Net revenue	274,789	1,192,620	—	1,467,409
Operating expenses	86,675	511,983	—	598,658
Administrative expenses	20,777	42,900	789	64,466
Depreciation and amortization	103,038	222,088	1,321	326,447
Gain on foreign exchange	—	—	373	373
Operating income	64,299	415,649	(2,483)	477,465
Interest expense	47,565	126,790	28,276	202,631
Interest, dividend, equity and other income	(3,723)	(5,449)	(2,817)	(11,989)
Other expenses (gain)	2,282	(4,250)	62,751	60,783
Earnings (loss) before income taxes	$ 18,175	$ 298,558	$ (90,693)	$ 226,040
Property, plant and equipment	$ 2,818,697	$ 5,047,454	$ 43,342	$ 7,909,493
Equity-method investees	37,273	2,784	422	40,479
Total assets	3,103,999	7,299,576	130,060	10,533,635
Capital expenditures	211,328	528,695	—	740,023

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

	Year ended December 31, 2016			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 265,949	$ 830,069	$ —	$ 1,096,018
Fuel and power purchased	21,260	274,055	—	295,315
Net revenue	244,689	556,014	—	800,703
Operating expenses	72,346	260,595	60	333,001
Administrative expenses	19,656	26,272	421	46,349
Depreciation and amortization	80,094	105,448	1,357	186,899
Gain on foreign exchange	—	—	(436)	(436)
Operating income	72,593	163,699	(1,402)	234,890
Interest expense	21,847	50,671	59,074	131,592
Interest, dividend and other income	32	(5,282)	(5,323)	(10,573)
Other expense (gain)	(14,403)	(11,690)	10,454	(15,639)
Earnings (loss) before income taxes	$ 65,117	$ 130,000	$ (65,607)	$ 129,510
Property, plant and equipment	$ 2,455,336	$ 2,390,047	$ 44,563	$ 4,889,946
Equity-method investees	59,021	2,314	3,084	64,419
Total assets	2,771,651	5,388,966	88,843	8,249,460
Capital expenditures	141,420	264,323	—	405,743

The majority of non-regulated energy sales are earned from contracts with large public utilities. The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations. None of the utilities contribute more than 10% of total revenue.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2017	2016
Revenue		
Canada	**$ 95,326**	$ 100,403
United States	**1,882,483**	995,615
	$ 1,977,809	$ 1,096,018
Property, plant and equipment		
Canada	**$ 568,693**	$ 558,271
United States	**7,340,800**	4,331,675
	$ 7,909,493	$ 4,889,946
Intangible assets		
Canada	**$ 34,654**	$ 36,611
United States	**29,454**	28,378
	$ 64,108	$ 64,989

Revenue is attributed to the two countries based on the location of the underlying generating and utility facilities.

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

Condemnation Expropriation Proceedings

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula could proceed with condemnation of Mountain Water's assets. The fair market value of the condemned property as of May 6, 2014 was assessed by the Commissioners to be U.S. $88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid U.S. $83,863 to Mountain Water, net of closing adjustments and amounts required to be paid by the City directly to various developers in satisfaction of obligations under Funded By Other (FBO) contracts relating to the assets.

In connection with Liberty Utilities' indirect acquisition of Mountain Water in January 2016, Liberty Utilities was permitted and continues to hold-back U.S. $14,400 from the purchase price otherwise payable to Carlyle Infrastructure Partners, L.P. ("Carlyle") and certain other interest holders.

The condemnation of the Mountain Water assets resulted in a gain on long-lived assets of U.S. $4,370.

Liberty Utilities (Apple Valley Ranchos Water) Corp. is the subject of a condemnation lawsuit filed by the town of Apple Valley. A Court will determine the necessity of the taking by Apple Valley and, if established, a jury will determine the fair market value of the assets being condemned. Resolution of the condemnation proceedings is expected to take two to three years. Any taking by government entities would legally require fair compensation to be paid, however, there is no assurance that the value received as a result of the condemnation will be sufficient to recover the Company's net book value of the utility assets taken.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2017.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases.

Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase (i)	$ 74,025	$ 48,344	$ 49,940	$ 50,214	$ 50,495	$ 254,380	$ 527,398
Gas supply and service agreements (ii)	91,425	66,848	51,809	33,161	28,411	97,489	369,143
Service agreements	47,695	47,211	48,529	48,827	46,548	435,093	673,903
Capital projects	41,054	17,064	65	65	65	16	58,329
Operating leases	9,573	8,974	8,298	8,361	9,718	225,047	269,971
Total	$263,772	$188,441	$158,641	$140,628	$135,237	$ 1,012,025	$ 1,898,744

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies (continued)

(b) Commitments (continued)

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2017. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

24. Non-cash operating items

The changes in non-cash operating items consist of the following:

	2017	2016
Accounts receivable	**$ (18,502)**	$ 6,612
Fuel and natural gas in storage	**(1,970)**	6,877
Supplies and consumable inventory	**1,392**	692
Income taxes receivable	**1,674**	145
Prepaid expenses	**(897)**	(6,161)
Accounts payable	**(23,178)**	24,524
Accrued liabilities	**25,122**	(9,454)
Current income tax liability	**(3,432)**	(4,552)
Net regulatory assets and liabilities	**(54,235)**	(14,979)
	$ (74,026)	$ 3,704

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments

(a) Fair value of financial instruments

2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 41,873	$ 47,912	$ —	$ 47,912	$ —
Derivative instruments [(1)]:					
Energy contracts designated as a cash flow hedge	79,490	79,490	—	—	79,490
Energy contracts not designated as a cash flow hedge	137	137	—	137	—
Commodity contracts for regulated operations	92	92	—	92	—
Transmission congestion rights	7,812	7,812	—	7,812	—
Total derivative instruments	87,531	87,531	—	8,041	79,490
Total financial assets	$ 129,404	$ 135,443	$ —	$ 55,953	$ 79,490
Long-term debt	$3,863,296	$4,093,071	$ 817,895	$3,275,176	$ —
Convertible debentures	1,218	1,277	1,277	—	—
Preferred shares, Series C	18,464	18,973		18,973	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	97	97	—	—	97
Energy contracts not designated as a cash flow hedge	39	39	—	39	—
Cross-currency swap designated as a net investment hedge	72,023	72,023	—	72,023	—
Interest rate swap designated as a hedge	10,613	10,613	—	10,613	—
Currency forward contract not designated as a hedge	432	432	—	432	—
Commodity contracts for regulated operations	3,286	3,286	—	3,286	—
Total derivative instruments	86,490	86,490	—	86,393	97
Total financial liabilities	$3,969,468	$4,199,811	$ 819,172	$3,380,542	$ 97

(1) Balance of $553 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 38,183	$ 47,933	$ —	$ 47,933	$ —
Derivative instruments [1]:					
Energy contracts designated as a cash flow hedge	84,554	84,554	—	—	84,554
Interest rate swap designated as a hedge	48,093	48,093	—	48,093	—
Currency forward contract not designated as a hedge	17,864	17,864	—	17,864	—
Commodity contracts for regulatory operations	359	359	—	359	—
Total derivative instruments	150,870	150,870	—	66,316	84,554
Total financial assets	$ 189,053	$ 198,803	$ —	$ 114,249	$ 84,554
Long-term debt	$3,913,415	$3,999,266	$ 517,637	$3,481,629	$ —
Convertible debentures	358,619	455,975	455,975	—	—
Preferred shares, Series C	18,460	18,613	—	18,613	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	95,404	95,404	—	95,404	—
Interest rate swaps designated as a hedge	13,385	13,385	—	13,385	—
Commodity contracts for regulated operations	36	36	—	36	—
Total derivative instruments	108,825	108,825	—	108,825	—
Total financial liabilities	$4,399,319	$4,582,679	$ 973,612	$3,609,067	$ —

(1) Balance of $314 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2017 and 2016 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace. Transmission congestion rights positions are fair valued using the most recent monthly auction clearing prices.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $22.13 to $121.56 with a weighted average of $33.20 as of December 31, 2017. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 25(b)(ii) and 25(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2017 and 2016.

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas and electric service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

		2017
Financial contracts:	Swaps	2,518,812
	Options	518,866
	Forward contracts	12,420,000
		15,457,678

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

	2017	2016
Regulatory assets:		
Swap contracts	U.S. **$ —**	U.S. $ —
Option contracts	U.S. **$ —**	U.S. $ 27
Forward contracts	U.S. **$ 6,319**	U.S. $ —
Regulatory liabilities:		
Swap contracts	U.S. **$ 287**	U.S. $ 175
Option contracts	U.S. **$ 138**	U.S. $ 92
Forward contracts	U.S. **$ 20,909**	U.S. $ —

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
688,147	December 2023	U.S. $ 40.40	PJM Western HUB
2,926,922	December 2023	U.S. $ 29.26	NI HUB
3,330,876	December 2027	U.S. $ 36.46	ERCOT North HUB

On October 25, 2016, the Company entered into forward contracts to purchase U.S. $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500,000 bonds in relation to the acquisition of Empire (note 9(e)). The change in fair value to February 13, 2017 resulted in a gain of U.S. $36,667. The effective portion of the hedge of U.S. $718 for the year ended December 31, 2017 was recorded in OCI while the ineffective portion was recorded in the consolidated statement of operations.

The Company is party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a gain of $2,771 for the year ended December 31, 2017 (2016 - loss of $3,726), which is recorded in OCI.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

		2017		2016
Effective portion of cash flow hedge, gain	$	**8,714**	$	34,355
Amortization of cash flow hedge		**(30)**		(47)
Gain reclassified from AOCI		**(6,775)**		(7,554)
OCI attributable to shareholders of APUC	$	**1,909**	$	26,754

The Company expects $11,612 and $2,643 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company designates the amounts drawn on the Liberty Power Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency gain of $21,648 for the year ended December 31, 2017 (2016 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A gain of $23,381 (2016 - $6,156) was recorded in OCI in 2017.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 25(b)(ii)).

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 8(d)). This risk was mitigated through the use of currency forward contracts to sell U.S. $38,400 for $47,225 between July 29, 2016 and September 29, 2016. As of December 31, 2017, these instruments had settled. This currency forward contract was not accounted for as a hedge.

The Company was exposed to foreign exchange fluctuations related to the acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk was mitigated through the conversion to U.S. dollars of $359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 14) and the use of a currency forward contract to buy an amount of U.S. $567,665 for $744,050 on January 31, 2017. This currency forward contract was not accounted for as a hedge. The settlement of the currency forward contract resulted in a total realized loss of $16,412 for the year ended December 31, 2017, which is recorded as a loss on foreign exchange in the consolidated statements of operations (2016 - gain of $17,684).

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk is mitigated through the use of currency forward contracts. For the year ended December 31, 2017, a loss on foreign exchange of $432 (2016 - $nil) was recorded in the consolidated statements of operations. These currency forward contracts are not accounted for as a hedge.

For derivatives that are not designated as hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	2017	2016
Change in unrealized loss (gain) on derivative financial instruments:		
Energy derivative contracts	**$ (52)**	$ (426)
Currency forward contract	**432**	(19,810)
Commodity contracts	**(3,916)**	—
Total change in unrealized gain on derivative financial instruments	**$ (3,536)**	$ (20,236)
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	**(193)**	—
Energy derivative contracts	**730**	951
Currency forward contract	**16,413**	(1,371)
Total realized loss (gain) on derivative financial instruments	**$ 16,950**	$ (420)
Loss (gain) on derivative financial instruments not accounted for as hedges	**13,414**	(20,656)
Ineffective portion of derivative financial instruments accounted for as hedges	**805**	1,518
	$ 14,219	$ (19,138)
Amounts recognized in the consolidated statements of operations consist of:		
Gain on derivative financial instruments	**(2,626)**	(15,849)
Loss (gain) on foreign exchange	**16,845**	(3,289)
	$ 14,219	$ (19,138)

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Liberty Power Group accounts receivable to be significant as over 90% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S. $204,380 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2017, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2017	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 26,259	$ 38,491
Accounts receivable	14,468	238,637
Allowance for doubtful accounts	—	(5,555)
Notes receivable	37,710	3,318
	$ 78,437	$ 274,891

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2017, in addition to cash on hand of $54,550 the Company had $1,145,859 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk (continued)

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long-term debt obligations	$ 279,724	$ 570,132	$ 644,969	$2,331,327	$3,826,152
Convertible Debentures	—	—	—	1,218	1,218
Advances in aid of construction	1,502	—	—	77,134	78,636
Interest on long-term debt	172,659	307,463	250,824	1,275,184	2,006,130
Purchase obligations	501,867	—	—	—	501,867
Environmental obligation	7,765	18,858	5,373	39,877	71,873
Derivative financial instruments:					
Cross-currency swap	4,386	8,077	64,726	(5,166)	72,023
Interest rate swaps	10,613	—	—	—	10,613
Currency forward	432	—	—	—	432
Energy derivative and commodity contracts	2,290	1,035	—	97	3,422
Other obligations	44,969	—	—	110,267	155,236
Total obligations	$1,026,207	$ 905,565	$ 965,892	$3,829,938	$6,727,602

26. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

Exhibit 99.3

ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company" or the "Corporation") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2017. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's consolidated financial statements for the years ended December 31, 2017 and 2016. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

Unless otherwise indicated, financial information provided for the years ended December 31, 2017 and 2016 has been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

This MD&A is based on information available to management as of March 7, 2018.

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Caution Concerning Forward-looking Statements, Forward-looking Information and non-GAAP Measures

Forward-looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC's target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the "safe harbor" provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation's acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "*Enterprise Risk Management*" and in the Corporation's AIF.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, one-time costs of arranging tax equity financing, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations, unrealized mark-to-market revaluation impacts, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. For 2017, the one-time impact of the revaluation of U.S. non-regulated net deferred income tax assets as a result of the U.S. federal corporate income tax rate reduction from 35% to 21% enacted in December 2017 is adjusted as it is also considered a non-recurring item not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, which can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's most recent AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flows to support a growing dividend and share price appreciation.

APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 per common share per annum. Based on exchange rates as at February 28, 2018, the quarterly dividend is equivalent to Cdn $0.1492 per common share or Cdn $0.5969 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Power Group, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets; and the Liberty Utilities Group. which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 87% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which as of December 31, 2017 had a production-weighted average remaining contract life of approximately 15 years.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 762,000 customers. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers and seeks to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisition of additional utility systems.

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas. The electric utility systems in total serve approximately 265,000 electric connections and operate a fleet of generation assets with a net capacity of 1,424 MW.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri serving approximately 337,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, and Texas which together serve approximately 160,000 connections.

Corporate Development

The Company is presently developing a portfolio of renewable power generation projects that, when constructed, will add approximately 361 MW of generation capacity from wind and solar powered generating facilities and, that when completed and on-line, will have a production-weighted average contract life of approximately 22 years.

2017 Major Highlights

Corporate Highlights

Strong Year of Operating Results

APUC recorded a strong twelve months of operating results relative to the same period last year.

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31		
	2017	2016	Change
Net earnings attributable to shareholders	**$193.1**	$130.9	**48%**
Adjusted Net Earnings	**$292.1**	$161.6	**81%**
Adjusted EBITDA	**$883.4**	$476.9	**85%**
Net earnings per common share	**$0.48**	$0.44	**9%**
Adjusted Net Earnings per common share	**$0.74**	$0.57	**30%**

Declaration of Canadian Equivalent 2018 First Quarter Dividend of Cdn $0.1492 (U.S. $0.1165) per Common Share

On March 1, 2018, APUC announced that the Board of Directors of APUC declared a first quarter 2018 dividend of U.S. $0.1165 per common share payable on April 13, 2018 to shareholders of record on March 29, 2018. Based on the Bank of Canada exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2018 dividend is set at Cdn $0.1492 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Total
U.S. dollar dividend	$0.1165	$0.1165	$0.1165	$0.1165	$0.4660
Canadian dollar equivalent	$0.1593	$0.1480	$0.1478	$0.1492	$0.6043

Investment in Joint Venture with Abengoa and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC entered into an agreement to create a joint venture, Abengoa-Algonquin Global Energy Solutions ("AAGES"), with Seville, Spain-based Abengoa, S.A (MCE: ABG) ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608 million, based on a price of U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per share payable two years after closing, subject to certain conditions. The transaction is expected to close sometime in the first quarter of 2018.

Completion of The Empire District Electric Company Acquisition and Financing

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of The Empire District Electric Company ("Empire") for an aggregate purchase price of approximately U.S. $2.414 billion including the assumption of approximately U.S. $0.9 billion of debt ("Empire Acquisition").

Empire is a Joplin, Missouri-based vertically integrated, regulated electric, gas and water utility with approximately 1.4 GW of generating capacity serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Empire Acquisition, the final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Empire Acquisition ("Acquisition Facility"). As at March 6, 2018, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

U.S. $750 Million Private Placement Offering

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750 million of senior unsecured notes on a private placement basis to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and an effective interest rate of 3.6% (inclusive of interest rate hedges).

Corporate Financings Completed:

$576 Million Bought Deal Offering of Common Shares

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result, a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

U.S. Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. Tax Reform") was signed into law in the U.S., which, amongst other significant changes, reduced the U.S. federal corporate tax rate from 35% to 21%.

As a result of U.S. Tax Reform, the Company is required to revalue its U.S. deferred income tax assets and liabilities based on the new tax rate. This revaluation resulted in a one time non-cash accounting charge of $22.4 million to be recorded in the Company's consolidated statement of operations for the quarter and year ended December 31, 2017.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company expects its effective tax rate in 2018 on its consolidated worldwide net income to be below 20%.

Additional detail on U.S. Tax Reform can be found later in this document under Corporate and Other expenses.

Change to U.S. Dollar Reporting

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Over 90% of APUC's consolidated revenue, EBITDA and assets are derived from operations in the United States. In addition, APUC's dividend is denominated in U.S. dollars and the Company's common shares are listed on the New York Stock Exchange. The Company believes that the change in reporting to U.S. dollars will provide improved information to investors and allow for better assessment of its results without the effects of the change in currency on 90% of its operations.

Liberty Power Group Highlights

Completion of the Deerfield Wind Project

On February 21, 2017, the Deerfield Wind Facility achieved commercial operations ("COD"). The project consists of a 150 MW wind generating facility located in central Michigan. On May 10, 2017, tax equity financing of approximately U.S. $166.6 million was completed. The Deerfield Wind Facility is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is expected to generate 555.2 GW-hrs annually. The project has a 20 year Power Purchase Agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

On January 11, 2017, the Liberty Power Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds were used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Liberty Utilities Group Highlights

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million. The Liberty Utilities Group has pending rate case filings in progress that are expected to be completed in 2018 that if successful will represent an increase in rates in the amount of U.S. $44.9 million.

Application to Develop up to 800 MW of Wind in the Midwest

On October 31, 2017, Empire announced a proposed plan to phase out its Asbury coal generation facility and expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. The plan projects cost savings for customers of U.S. $172.0 - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. Orders from the various jurisdictions are anticipated by June 2018.

Granite Bridge Project

On December 4, 2017, the Liberty Utilities Group announced plans for the development of a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project is estimated to cost between U.S. $320.0 million and U.S. $360 million and would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York State. The total purchase price for the transaction is U.S. $70.0 million, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

Acquisition of the Perris Water Distribution System

On August 10, 2017, the Company's board approved the acquisition of two water distribution systems serving approximately 4,000 customers in the City of Perris, California. The anticipated purchase price of U.S. $11.5 million is expected to be established as rate base during the regulatory approval process. Liberty Utilities was the successful bidder in the city's request for proposal process and in July 2017 the Perris City council voted to approve the sale to Liberty Utilities. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission ("CPUC") in Q1 2018, with approval expected in late 2018.

Completion of the Luning Solar Facility

On February 15, 2017, the Liberty Utilities Group acquired control of a 50 MWac solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The facility is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the facility is included in the rate base of the Calpeco Electric System as energy produced from the project is being consumed by the utility's customers.

2017 Fourth Quarter Results From Operations

Key Financial Information (all dollar amounts in $ millions except per share information)	Three Months Ended December 31 2017	2016
Revenue	**$ 523.4**	$ 310.2
Net earnings attributable to shareholders	**60.0**	46.3
Cash provided by operating activities	**169.8**	121.9
Adjusted Net Earnings[1]	**85.9**	51.4
Adjusted EBITDA[1]	**233.4**	138.3
Adjusted Funds from Operations[1]	**159.1**	96.4
Dividends declared to common shareholders	**64.0**	39.2
Weighted average number of common shares outstanding	**412,632,308**	273,952,963
Per share		
Basic net earnings	**$ 0.14**	$ 0.16
Diluted net earnings	**$ 0.14**	$ 0.16
Adjusted Net Earnings[1,2]	**$ 0.20**	$ 0.18
Dividends declared to common shareholders	**$ 0.15**	$ 0.14

1 See Non-GAAP Financial Measures

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2715 as compared to 1.3343 in the same period in 2016. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2017, APUC reported total revenue of $523.4 million as compared to $310.2 million during the same period in 2016, an increase of $213.2 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	$	**310.2**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.4)
Wind Canada: Increase primarily due to higher production and annual rate increases in PPAs.		1.9
Wind U.S.: Increase primarily due to higher overall production.		1.3
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		2.9
Other:		(0.5)
		5.4
New Facilities		
Wind US: Acquisition of Deerfield Wind Facility in March 2017.		9.5
Solar US: Bakersfield II Solar Facility was placed in service in December 2016.		0.3
		9.8
Foreign Exchange		**(2.3)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(7.2)
Gas: Increase primarily due to higher demand and pass through gas costs at the New England and Midstates Gas Systems from increased heating degree days, partially offset by lower pass through gas costs at the EnergyNorth Gas System.		14.5
Water: Decrease primarily due to divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(2.9)
Other: Decrease primarily due to lower contracted services.		(1.8)
		2.6
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($180.8 million) on January 1, 2017 and the Luning Solar Facility ($3.6 million) on February 15, 2017.		184.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		14.6
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.6
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.0
		201.6
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(11.0)**
Current Period Revenue	$	**523.4**

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2017, net earnings attributable to shareholders totaled $60.0 million as compared to $46.3 million during the same period in 2016, an increase of $13.7 million or 29.6%. The increase was due to a $101.6 million increase in earnings from operating facilities and a $1.1 million decrease in acquisition related costs. These items were partially offset by a $5.6 million increase in administration charges, $35.4 million increase in depreciation and amortization expenses, $0.3 million decrease in foreign exchange gain, $3.7 million increase in interest expense, $0.6 million decrease in interest, dividend, equity and other income, $3.3 million decrease in other gains, $2.3 million decrease in gains on long lived assets, $8.9 million decrease in gains from derivative instruments, $2.4 million decrease in net effect of non-controlling interests, and a $26.5 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2016.

During the three months ended December 31, 2017, cash provided by operating activities totaled $169.8 million as compared to cash provided by operating activities of $121.9 million during the same period in 2016. During the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million compared to Adjusted Funds from Operations of $96.4 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended December 31, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended December 31, 2017, Adjusted EBITDA totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31 2017	2016	2015
Revenue	**$ 1,977.8**	$ 1,096.0	$ 1,027.9
Net earnings attributable to shareholders from continuing operations	**193.1**	130.9	118.5
Net earnings attributable to shareholders	**193.1**	130.9	117.5
Cash provided by operating activities	**457.8**	287.9	261.9
Adjusted Net Earnings[1]	**292.1**	161.6	121.5
Adjusted EBITDA[1]	**883.4**	476.9	375.4
Adjusted Funds from Operations[1]	**614.5**	356.4	287.4
Dividends declared to common shareholders	**242.5**	149.2	124.8
Weighted average number of common shares outstanding	**382,323,434**	271,832,430	253,172,088
Per share			
Basic net earnings from continuing operations	**$ 0.48**	$ 0.44	$ 0.43
Basic net earnings	**$ 0.48**	$ 0.44	$ 0.42
Diluted net earnings	**$ 0.47**	$ 0.44	$ 0.42
Adjusted Net Earnings[1,2]	**$ 0.74**	$ 0.57	$ 0.46
Dividends declared to common shareholders	**$ 0.61**	$ 0.55	$ 0.49
Total assets	**10,533.6**	8,249.5	4,991.7
Long term debt[3]	**3,864.5**	4,272.0	1,486.8

1 See Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

3 Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the twelve months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2980 as compared to 1.3253 in the same period in 2016. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2017, APUC reported total revenue of $1,977.8 million as compared to $1,096.0 million during the same period in 2016, an increase of $881.8 million or 80.5%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)	Twelve Months Ended December 31
Comparative Prior Period Revenue	**$ 1,096.0**
LIBERTY POWER GROUP	
Existing Facilities	
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and lower pricing in Hydro Quebec PPA renewals, coupled with lower production in the Maritime and Western Regions.	(7.5)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.	2.2
Wind U.S.: Decrease primarily due to lower REC pricing, partially offset by higher production at Minonk and Shady Oaks Wind Facilities.	(0.8)
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.	(0.6)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.	(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.	4.2
Other: Decrease primarily due to the shutdown of the hydro mulch business at the Sanger Thermal Facility.	(1.9)
	(4.8)
New Facilities	
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.	40.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.	2.1
	42.9
Foreign Exchange	**(3.6)**
LIBERTY UTILITIES GROUP	
Existing Facilities	
Electricity: Decrease primarily due to lower pass through energy costs at the Calpeco Electric System.	(8.3)
Gas: Increase primarily due to higher consumption at the EnergyNorth and New England Gas Systems due to higher heating degree days combined with higher pass through gas costs at the Peach State Gas System.	38.0
Water: Decrease primarily due divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.	(6.5)
Other: Decrease primarily due to lower contracted services.	(6.0)
	17.2
New Facilities	
Electricity: Acquisition of both Empire's electric distribution system ($754.6 million) on January 1, 2017 and the Luning Solar Facility ($14.7 million) on February 15, 2017.	769.3
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.	46.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.	2.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.	8.1
	827.0
Rate Cases	
Electricity: Implementation of new rates at the Granite State Electric System.	5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.	12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.	6.1
	23.8
Foreign Exchange	**(20.7)**

Current Period Revenue	**$**	**1,977.8**

A more detailed discussion of these factors is presented within the business unit analysis.

For the twelve months ended December 31, 2017, net earnings attributable to shareholders totaled $193.1 million as compared to $130.9 million during the same period in 2016, an increase of $62.2 million. The increase was due to a $401.4 million increase in earnings from operating facilities, $1.4 million increase in interest, dividend, equity and other income, and $23.6 million increase in net effect of non-controlling interests. These items were partially offset by an $18.2 million increase in administration charges, $139.5 million increase in depreciation and amortization expenses, $0.8 million decrease in foreign exchange gains, $71.0 million increase in interest expense, $11.8 million decrease in other gains, $50.8 million increase in acquisition costs, $0.8 million decrease in gain on long lived assets, $13.2 million decrease on gains from derivative instruments and $58.1 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*) as compared to the same period in 2016.

During the twelve months ended December 31, 2017, cash provided by operating activities totaled $457.8 million as compared to cash provided by operating activities of $287.9 million during the same period in 2016. During the twelve months ended December 31, 2017, Adjusted Funds from Operations, a non-GAAP measure, totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million the same period in 2016, an increase of $258.1 million.

Adjusted EBITDA in the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2017 totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. Adjusted EBITDA for the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	**Three Months Ended December 31**		**Twelve Months Ended December 31**	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Liberty Power Operating Profit	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3
Liberty Utilities Group Operating Profit	**180.7**	85.9	**694.1**	300.5
Administrative Expenses	**(18.7)**	(13.1)	**(64.5)**	(46.3)
Other Income & Expenses	**0.6**	3.6	**2.9**	5.4
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9
Change in Adjusted EBITDA ($)	**$ 95.1**		**$ 406.5**	
Change in Adjusted EBITDA (%)	**68.8%**		**85.2%**	

Change in Adjusted EBITDA	**Three Months Ended December 31, 2017**			
(all dollar amounts in $ millions)	**Power**	**Utilities**	**Corporate**	**Total**
Prior period balances	**$ 61.9**	**$ 85.9**	**$ (9.5)**	**$ 138.3**
Existing Facilities	7.8	(5.6)	(3.0)	(0.8)
New Facilities	3.0	97.3	—	100.3
Rate Cases	—	7.1	—	7.1
Foreign Exchange Impact	(1.9)	(4.0)	—	(5.9)
Administrative Expenses	—	—	(5.6)	(5.6)
Total change during the period	**$ 8.9**	**$ 94.8**	**$ (8.6)**	**$ 95.1**
Current period balances	**$ 70.8**	**$ 180.7**	**$ (18.1)**	**$ 233.4**

Change in Adjusted EBITDA	**Twelve Months Ended December 31, 2017**			
(all dollar amounts in $ millions)	**Power**	**Utilities**	**Corporate**	**Total**
Prior period balances	**$ 217.3**	**$ 300.5**	**$ (40.9)**	**$ 476.9**
Existing Facilities	0.9	(4.5)	(2.6)	(6.2)
New Facilities	34.9	381.0	—	415.9
Rate Cases	—	23.8	—	23.8
Foreign Exchange Impact	(2.2)	(6.7)	—	(8.9)
Administration Expenses	—	—	(18.1)	(18.1)
Total change during the period	**$ 33.6**	**$ 393.6**	**$ (20.7)**	**$ 406.5**
Current period balances	**$ 250.9**	**$ 694.1**	**$ (61.6)**	**$ 883.4**

LIBERTY POWER GROUP

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Long Term Average Resource	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Hydro Facilities:						
Maritime Region	**37.6**	**34.9**	21.9	**148.2**	**129.7**	144.1
Quebec Region	**72.6**	**67.5**	64.0	**273.3**	**270.6**	267.5
Ontario Region	**31.9**	**30.6**	28.6	**136.0**	**129.5**	126.8
Western Region	**12.6**	**10.5**	18.1	**65.0**	**59.6**	66.1
	154.7	**143.5**	132.6	**622.5**	**589.4**	604.5
Wind Facilities:						
St. Damase	**22.7**	**24.0**	20.4	**76.9**	**74.3**	74.4
St. Leon	**121.4**	**138.7**	130.8	**430.2**	**444.2**	417.3
Red Lily[1]	**24.1**	**29.2**	25.4	**88.5**	**91.6**	82.6
Morse	**30.5**	**33.1**	27.7	**108.8**	**106.4**	94.8
Sandy Ridge	**43.6**	**42.0**	51.8	**158.3**	**153.3**	155.8
Minonk	**189.8**	**203.5**	184.9	**673.7**	**673.7**	635.8
Senate	**140.0**	**126.6**	136.7	**520.4**	**492.8**	504.4
Shady Oaks	**100.5**	**108.7**	104.4	**355.6**	**365.5**	323.9
Odell[2]	**238.0**	**244.6**	211.2	**831.8**	**807.2**	297.7
Deerfield[3]	**160.0**	**164.3**	—	**472.6**	**449.3**	—
	1,070.6	**1,114.7**	893.3	**3,716.8**	**3,658.3**	2,586.7
Solar Facilities:						
Cornwall	**2.2**	**2.1**	1.9	**14.7**	**14.4**	15.6
Bakersfield I	**8.9**	**8.7**	7.4	**52.8**	**48.3**	45.9
Bakersfield II[4]	**4.1**	**4.0**	—	**24.4**	**22.2**	—
	15.2	**14.8**	**9.3**	**91.9**	**84.9**	**61.5**
Renewable Energy Performance	**1,240.5**	**1,273.0**	1,035.2	**4,431.2**	**4,332.6**	3,252.7
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**31.8**	30.9	**N/A[5]**	**122.0**	131.0
Sanger	**N/A[5]**	**33.5**	28.8	**N/A[5]**	**86.0**	118.7
		65.3	59.7		**208.0**	249.7
Total Performance		**1,338.3**	1,094.9		**4,540.6**	3,502.4

[1] APUC owns a 75% equity interest in the Red Lily Wind Facility but accounts for the facility using the equity method. The production figures represent full energy produced by the facility.

[2] The Odell Wind Facility achieved COD on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility.

[3] The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The long-term average resources ("LTAR") and production noted above represents all production from the date of COD.

[4] The Bakersfield II Solar Facility achieved COD on January 11, 2017 in accordance with the terms of the PPA. The LTAR and production noted above represents all production from the date of COD.

[5] Natural gas fired co-generation facility.

2017 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2017, the Liberty Power Group generated 1,338.3 GW-hrs of electricity as compared to 1,094.9 GW-hrs during the same period of 2016.

For the three months ended December 31, 2017, the hydro facilities generated 143.5 GW-hrs of electricity as compared to 132.6 GW-hrs produced in the same period in 2016, an increase of 8.2%. Electricity generated represented 92.8% of long-term average resources ("LTAR") as compared to 85.7% during the same period in 2016. During the quarter, all regions were below their respective LTAR.

For the three months ended December 31, 2017, the wind facilities produced 1,114.7 GW-hrs of electricity as compared to 893.3 GW-hrs produced in the same period in 2016, an increase of 24.8%. The higher generation was primarily due to the addition of the Deerfield Wind Facility which achieved COD on February 21, 2017. This increase was partially offset by lower production at the Senate and Sandy Ridge Wind Facilities. During the three months ended December 31, 2017, the wind facilities (excluding the Deerfield Wind Facility) generated electricity equal to 104.3% of LTAR as compared to 98.0% during the same period in 2016.

For the three months ended December 31, 2017, the solar facilities generated 14.8 GW-hrs of electricity as compared to 9.3 GW-hrs of electricity in the same period in 2016, an increase of 59.1%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 2.7% below its LTAR as compared to 16.2% below in the same period in 2016.

For the three months ended December 31, 2017, the thermal facilities generated 65.3 GW-hrs of electricity as compared to 59.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 136.9 billion lbs of steam as compared to 129.3 billion lbs of steam during the same period in 2016.

2017 Annual Liberty Power Group Performance

For the twelve months ended December 31, 2017, the Liberty Power Group generated 4,540.6 GW-hrs of electricity as compared to 3,502.4 GW-hrs during the same period of 2016.

For the twelve months ended December 31, 2017, the hydro facilities generated 589.4 GW-hrs of electricity as compared to 604.5 GW-hrs produced in the same period in 2016, a decrease of 2.5%. Electricity generated represented 94.7% of long-term projected average resources as compared to 97.1% during the same period in 2016. The decrease is primarily due to reduced hydrology in the Maritime and Western Region's partially offset by increased generation in the Quebec and Ontario Regions.

For the twelve months ended December 31, 2017, the wind facilities produced 3,658.3 GW-hrs of electricity as compared to 2,586.7 GW-hrs produced in the same period in 2016, an increase of 41.4%. During the twelve months ended December 31, 2017, the wind facilities generated electricity equal to 98.4% of LTAR as compared to 93.9% during the same period in 2016. The increase in production was primarily due to higher production at the Shady Oaks, Minonk and St. Leon Wind Facilities as well as the incremental electricity generated at the Deerfield and Odell Wind Facilities which achieved COD on February 21, 2017 and July 29, 2016, respectively.

For the twelve months ended December 31, 2017, the solar facilities generated 84.9 GW-hrs of electricity as compared to 61.5 GW-hrs of electricity produced in the same period in 2016, an increase of 38.0%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 7.1% below its LTAR as compared to 8.9% below in the same period in 2016.

For the twelve months ended December 31, 2017, the thermal facilities generated 208.0 GW-hrs of electricity as compared to 249.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 559.1 billion lbs of steam as compared to 552.5 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Revenue[1]				
Hydro	**$ 14.0**	$ 14.6	**$ 58.2**	$ 66.5
Wind	**54.0**	42.6	**171.6**	128.2
Solar	**2.0**	1.6	**14.0**	12.9
Thermal	**11.1**	8.2	**38.8**	35.5
Total Revenue	**$ 81.1**	$ 67.0	**$ 282.6**	$ 243.1
Less:				
Cost of Sales - Energy[2]	**(1.9)**	(1.8)	**(6.5)**	(5.8)
Cost of Sales - Thermal	**(5.8)**	(4.4)	**(18.9)**	(15.5)
Realized gain/(loss) on hedges[3]	**—**	—	**(0.7)**	(1.0)
Net Energy Sales	**$ 73.4**	$ 60.8	**$ 256.5**	$ 220.8
Renewable Energy Credits ("REC")[4]	**5.5**	6.3	**17.1**	20.2
Other Revenue	**0.1**	0.5	**0.5**	2.4
Total Net Revenue	**$ 79.0**	$ 67.6	**$ 274.1**	$ 243.4
Expenses & Other Income				
Operating expenses	**(21.9)**	(20.2)	**(86.7)**	(72.3)
Interest, dividend, equity and other income	**1.1**	0.9	**3.7**	5.2
HLBV income[5]	**12.6**	13.6	**59.8**	41.0
Divisional Operating Profit[6,7]	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3

[1] While most of the Liberty Power Group's PPAs include annual rate increases, a change to the weighted average production levels resulting from higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division as compared to the same period in the prior year.

[2] Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Hydro Facility which is sold to retail and industrial customers under multi-year contracts.

[3] See financial statements *note 25(b)(iv)*.

[4] Qualifying renewable energy projects receive RECs for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source.

[5] HLBV income represents the value of net tax attributes earned by the Liberty Power Group in the period primarily from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

[6] Certain prior year items have been reclassified to conform to current year presentation.

[7] See *Non-GAAP Financial Measures*.

2017 Fourth Quarter Operating Results

For the three months ended December 31, 2017, the Liberty Power Group's facilities generated $70.8 million of operating profit as compared to $61.9 million during the same period in 2016, which represents an increase of $8.9 million or 14.4%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31	
Prior Period Operating Profit	**$**	**61.9**
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.6)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		1.9
Wind U.S.: Increase primarily due to higher production and HLBV income at the Minonk and Odell Wind Facilities.		4.7
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.3
Thermal: Increase primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		1.3
Other:		0.1
		7.8
New Facilities		
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.		2.2
Solar U.S.: Bakersfield II was placed in service in December 2016.		0.8
		3.0
Foreign Exchange		**(1.9)**
Current Period Divisional Operating Profit	**$**	**70.8**

2017 Annual Operating Results

For the twelve months ended December 31, 2017, the Liberty Power Group's facilities generated $250.9 million of operating profit as compared to $217.3 million during the same period in 2016, which represents an increase of $33.6 million or 15.5%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	**$**	**217.3**
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and pricing settlement in the Quebec Region, coupled with lower production in the Maritime and Western Regions.		(8.2)
Wind Canada: Increase primarily due to higher production and annual rate increases.		1.8
Wind U.S.: Increase primarily due to higher HLBV income and higher production at the Minonk and Shady Oaks Wind Facilities.		6.7
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.2)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at to the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		0.4
Other:		0.8
		0.9
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		31.3
Solar U.S.: Bakersfield II was placed in service in December 2016.		3.6
		34.9
Foreign Exchange		**(2.2)**
Current Period Divisional Operating Profit	**$**	**250.9**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, the Liberty Utilities Group completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

Utility System Type

(all dollar amounts in U.S. $ millions)	As at December 31 2017			2016		
		Assets	Total Connections[1]		Assets	Total Connections[1]
Electricity	$	**2,479.9**	**265,000**	$	378.4	94,000
Natural Gas		**996.1**	**337,000**		845.9	293,000
Water and Wastewater		**462.6**	**160,000**		516.4	178,000
Total	$	**3,938.6**	**762,000**	$	1,740.7	565,000
Accumulated Deferred Income Taxes Liability	$	**392.8**		$	194.7	

[1] Total Connections represents the sum of all active and vacant connections.

The Liberty Utilities Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 265,000 connections in the states of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 337,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 160,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

2017 Fourth Quarter Usage Results

Electric Distribution Systems

	Three Months Ended December 31 2017	2016
Average Active Electric Connections For The Period		
Residential	224,400	80,600
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**263,600**	**93,100**
Customer Usage (GW-hrs)		
Residential	571.7	142.5
Commercial and industrial	882.3	225.0
Total Customer Usage (GW-hrs)	**1,454.0**	**367.5**

For the three months ended December 31, 2017, the electric distribution systems' usage totaled 1,454.0 GW-hrs as compared to 367.5 GW-hrs for the same period in 2016, an increase of 1,086.5 GW-hrs or 295.6%. The addition of Empire accounted for 1,091.6 GW-hrs of the increase. Excluding Empire, usage was 5.1 GW-hrs, or 1.4%, lower due to lower commercial usage at the Calpeco Electric System.

Natural Gas Distribution Systems

	Three Months Ended December 31	
	2017	2016
Average Active Natural Gas Connections For The Period		
Residential	286,700	248,100
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,400**	**274,700**
Customer Usage (MMBTU)		
Residential	5,196,000	3,737,000
Commercial and industrial	4,282,000	3,446,000
Total Customer Usage (MMBTU)	**9,478,000**	**7,183,000**

For the three months ended December 31, 2017, usage at the natural gas distribution systems totaled 9,478,000 MMBTU as compared to 7,183,000 MMBTU during the same period in 2016, an increase of 2,295,000 MMBTU, or 32.0%. The addition of Empire accounted for 1,069,000 MMBTU of the increase. Excluding Empire, usage was 1,226,000 MMBTU, or 17.1%, higher primarily due to increased consumption at the Midstates and Peach State Gas Systems.

Water and Wastewater Distribution Systems

	Three Months Ended December 31	
	2017	2016
Average Active Connections For The Period		
Wastewater connections	41,400	41,100
Water distribution connections	111,800	129,400
Total Average Active Connections For The Period	**153,200**	**170,500**
Gallons Provided		
Wastewater treated (millions of gallons)	555	542
Water provided (millions of gallons)	3,909	4,113
Total Gallons Provided	**4,464**	**4,655**

During the three months ended December 31, 2017, the water and wastewater distribution systems provided approximately 3,909 million gallons of water to its customers and treated approximately 555 million gallons of wastewater as compared to 4,113 million gallons of water provided and 542 million gallons of wastewater treated during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 289 million gallons, or 7%, higher.

2017 Fourth Quarter Operating Results

	Three Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 187.0**	$ 46.9	**$ 237.8**	$ 62.5
Less: cost of sales – electricity	**(51.6)**	(20.6)	**(65.6)**	(27.5)
Net Utility Sales - electricity	**135.4**	26.3	**172.2**	35.0
Utility natural gas sales and distribution	**109.8**	85.1	**140.0**	114.0
Less: cost of sales – natural gas	**(53.1)**	(39.8)	**(67.7)**	(53.2)
Net Utility Sales - natural gas	**56.7**	45.3	**72.3**	60.8
Utility water distribution & wastewater treatment sales and distribution	**31.5**	31.7	**40.1**	42.3
Less: cost of sales – water	**(2.4)**	(2.2)	**(3.1)**	(3.0)
Net Utility Sales - water distribution & wastewater treatment	**29.1**	29.5	**37.0**	39.3
Gas transportation	**9.6**	8.4	**12.3**	10.7
Other revenue	**5.1**	5.0	**6.5**	6.8
Net Utility Sales	**235.9**	114.5	**300.3**	152.6
Operating expenses	**(96.6)**	(50.5)	**(123.1)**	(68.0)
Other income	**1.4**	0.9	**1.8**	1.3
HLBV	**1.3**	—	**1.7**	—
Divisional Operating Profit[1]	**$ 142.0**	$ 64.9	**$ 180.7**	$ 85.9

1 Certain prior year items have been reclassified to conform with current year presentation.

For the three months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $142.0 million as compared to U.S. $64.9 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $180.7 million as compared to $85.9 million during the same period in 2016, which represents an increase of $94.8 million or 110%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Three Months Ended December 31
Prior Period Operating Profit	**$**	**85.9**
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(6.4)
Gas: Increase primarily due to higher consumption at the Midstates and EnergyNorth Gas Systems.		3.1
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(2.2)
Other: Decrease primarily due to lower contracted services.		(0.1)
		(5.6)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($85.9 million) on January 1, 2017 and the Luning Solar Facility ($4.9 million) on February 15, 2017.		90.8
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		4.3
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.9
		97.3
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(4.0)**
Current Period Divisional Operating Profit	**$**	**180.7**

2017 Annual Usage Results

Electric Distribution Systems

	Twelve Months Ended December 31	
	2017	2016
Average Active Electric Connections For The Period		
Residential	223,700	80,400
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**262,900**	**92,900**
Customer Usage (GW-hrs)		
Residential	2,320.1	567.0
Commercial and industrial	3,523.1	895.2
Total Customer Usage (GW-hrs)	**5,843.2**	**1,462.2**

For the twelve months ended December 31, 2017, the electric distribution systems' usage totaled 5,843.2 GW-hrs as compared to 1,462.2 GW-hrs for the same period in 2016, an increase of 4,381.0 GW-hrs. The addition of Empire accounted for 4,386.3 GW-hrs of the increase. Excluding Empire, usage was 5.3 GW-hrs, or 0.4%, lower due to decreased usage by commercial customers at the Granite State Electric System.

Natural Gas Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	287,100	249,000
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,800**	**275,600**
Customer Usage (MMBTU)		
Residential	17,621,000	15,346,000
Commercial and industrial	12,672,000	11,361,000
Total Customer Usage (MMBTU)	**30,293,000**	**26,707,000**

For the twelve months ended December 31, 2017, usage at the natural gas distribution systems totaled 30,293,000 MMBTU as compared to 26,707,000 MMBTU during the same period in 2016, an increase of 3,586,000 MMBTU or 13.4%. The addition of Empire accounted for 2,997,000 MMBTU of the increase. Excluding Empire, usage was 589,000 MMBTU, or 2.2%, higher due to increased usage at the EnergyNorth and New England Gas Systems.

Water and Wastewater Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	41,000	41,100
Water distribution connections	121,400	131,400
Total Average Active Connections For The Period	**162,400**	172,500
Gallons Provided		
Wastewater treated (millions of gallons)	2,226	2,231
Water provided (millions of gallons)	16,905	17,936
Total Gallons Provided	**19,131**	20,167

During the twelve months ended December 31, 2017, the water and wastewater distribution systems provided approximately 16,905 million gallons of water to its customers and treated approximately 2,226 million gallons of wastewater as compared to 17,936 million gallons of water and 2,231 million gallons of wastewater during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 2,295 million gallons, or 14%, higher.

2017 Annual Operating Results

	Twelve Months Ended December 31			
	2017 U.S. $ (millions)	**2016 U.S. $ (millions)**	**2017 Can $ (millions)**	**2016 Can $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 763.5**	$ 171.7	**$ 989.2**	$ 228.1
Less: cost of sales – electricity	**(222.4)**	(90.0)	**(288.2)**	(119.8)
Net Utility Sales - electricity	**541.1**	81.7	**701.0**	108.3
Utility natural gas sales and distribution	**346.0**	276.8	**450.7**	371.4
Less: cost of sales – natural gas	**(141.7)**	(105.0)	**(184.5)**	(142.1)
Net Utility Sales - natural gas	**204.3**	171.8	**266.2**	229.3
Utility water distribution & wastewater treatment sales and distribution	**140.1**	137.4	**181.9**	181.7
Less: cost of sales – water	**(9.5)**	(9.2)	**(12.3)**	(12.2)
Net Utility Sales - water distribution & wastewater treatment	**130.6**	128.2	**169.6**	169.5
Gas transportation	**31.2**	25.7	**40.7**	34.3
Other revenue	**11.8**	11.0	**15.2**	14.6
Net Utility Sales	**919.0**	418.4	**1,192.7**	556.0
Operating expenses	**(393.7)**	(196.1)	**(512.0)**	(260.6)
Other income	**4.2**	3.9	**5.4**	5.1
HLBV	**6.2**	—	**8.0**	—
Divisional Operating Profit[1]	**$ 535.7**	$ 226.2	**$ 694.1**	$ 300.5

1 Certain prior year items have been reclassified to conform with current year presentation.

For the twelve months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $535.7 million as compared to U.S. $226.2 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $694.1 million as compared to $300.5 million during the same period in 2016, which represents an increase of $393.6 million or 131%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	$	**300.5**
Existing Facilities		
Gas: Increase primarily due to higher consumption at the EnergyNorth Gas System.		4.5
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(5.3)
Other: Decrease primarily due to lower contracted services.		(3.7)
		(4.5)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($341.4 million) on January 1, 2017 and the Luning Solar Facility ($20.7 million) on February 15, 2017.		362.1
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		11.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		1.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		5.7
		381.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(6.7)**
Current Period Divisional Operating Profit	$	**694.1**

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities Group:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$7.7	Final Order issued in April 2017 approving a U.S. $6.2 million rate increase effective May 1, 2017, and two additional rate increases of approximately U.S. $0.2 million and U.S. $0.3 million effective May 1, 2018 and May 1, 2019, respectively.
New England Gas	Massachusetts	Gas System Enhancement Plan ("GSEP")	$3.8	Final Order issued in April 2017 approving a U.S. $2.9 million rate increase effective May 1, 2017.
Illinois Gas System	Illinois	GRC	$3.0	Final Order issued in May 2017 approving a U.S. $2.2 million rate increase effective June 7, 2017.
Oklahoma Electricity System	Oklahoma	GRC	$3.0	In August 2017, in lieu of authorizing the proposed rate increase the Oklahoma Corporation Commission ordered an immediate increase of U.S. $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.
Calpeco Electric	California	Turquoise Solar Project	$3.0	Final Order issued in December 2017 approving the Settlement Agreement between Liberty Calpeco and the Office of Ratepayer Advocates dated June 30, 2017 which authorizes Liberty Calpeco to acquire, own, and operate the 10 MW, U.S. $15.7 million Turquoise Solar Project.
Calpeco Electric	California	Post-Test Year Adjustment Mechanism	$2.2	Final Order issued in November 2017 approving a U.S $2.2 million rate increase effective January 1, 2018, based on the additional costs related to the Luning Solar Project.
Various	Various	Various	$4.8	Other rate cases closed in 2017 & 2018 with a combined approved rate increase of U.S. $2.8 million include: Entrada Del Oro Water (U.S. $0.2 million), Georgia Gas GRAM (U.S. $0.6 million), New England Gas Decoupling (U.S. $0.2 million), Iowa Gas GRC (U.S. $0.9 million), and Kansas Asbury Environmental and Riverton Cost Recovery Rider (U.S. $0.9 million).

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	GRC	$19.7	On April 28, 2017, filed an application seeking an increase of U.S. $13.7 million (updated to U.S. $14.5 million), plus a step increase of U.S. $6.1 million (updated to U.S. $5.2 million) to be implemented in May 2018. Temporary rates of U.S. $7.8 million were requested to be effective as of July 1, 2017, and on June 30, 2017, the New Hampshire Public Utilities Commission ("NH Commission") approved temporary rates of U.S. $6.8 million (87% of the requested amount) effective July 1, 2017 to be in place until the end of the Company's permanent rate case.
Litchfield Park Water & Sewer	Arizona	GRC	$5.1	On February 28, 2017, filed a water/sewer rate application (test year December 31, 2016) seeking a rate increase of U.S. $5.1 million. New rates are expected to be effective in Q4 2018.
Missouri Gas System	Missouri	GRC	$7.5	On September 29, 2017, filed an application seeking a rate increase of U.S. $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. New rates are expected to be effective in Q3 2018.
Apple Valley Ranchos Water & Park Water Systems	California	GRC	$2.1	On January 2, 2018, filed an application requesting an average rate increase of U.S. $0.7 million and U.S. $1.4 million, respectively and is to set rates for the three year period of 2019 to 2021.
New England Natural Gas System	Massachusetts	GSEP	$6.2	On October 31, 2017, filed the 2018 GSEP application requesting recovery of U.S. $6.2 million (effective May 1, 2018) for replacement of approximately 14 miles of eligible infrastructure.
Various	Various	Various	$4.3	Other pending rate case requests include: Woodmark/Tall Timbers Wastewater Systems (U.S. $1.6 million), Park Water System (U.S. $1.5 million), and Missouri Water System (U.S. $1.2 million).

Completed Rate Cases

On December 14, 2016, the Calpeco Electric System filed an application for approval of the 10 MW Turquoise Solar Project at an estimated cost of U.S. $15.7 million. On June 30, 2017, the Calpeco Electric System and the Office of Ratepayer Advocates filed a joint motion with the Commission requesting approval of its settlement agreement. On December 19, 2017, the Commission issued a decision approving the settlement agreement as filed. The Turquoise Solar Project costs will be included in the Calpeco Electric System's 2019 general rate case and is expected to have a rate impact of approximately U.S. $3.0 million (or 3% increase), which will be offset by future Energy Cost Adjustment Clause ("ECAC)" account reductions. The Turquoise Solar Project is expected to be in service by the fourth quarter of 2018.

On April 29, 2016, the Granite State Electric System filed a rate application seeking a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, plus an additional U.S. $2.4 million annual step increase to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase proposed was U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent rate increase was retroactive to the temporary rate effective date. In April 2017, an order was issued by the New Hampshire Public Utilities Commission ("NHPUC") approving a U.S. $3.8 million rate increase to annual distribution revenues along with an annual increase of U.S. $2.5 million for the revenue requirement associated with 2016 capital investment, both effective May 1, 2017 (achieving 82% of the requested increase). The difference between the U.S. $3.8 million permanent increase and the U.S. $2.4 million temporary rate level that was in effect since July 1, 2016 was collected beginning May 1, 2017. The settlement also provides for two additional annual increases of approximately U.S. $0.2 million and $0.3 million effective May 1, 2018 and May 1, 2019, respectively, to recover the revenue requirement associated with certain significant capital investments made during the prior calendar year.

Pending Regulatory Proceedings

On October 31, 2017, Empire District Electric Company announced a proposed plan to expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. Once fully operational, the project is projected to generate cost savings for customers of U.S. $172.0 million - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval ("Application") of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. On February 6, 2018, the staff of the Missouri Public Service Commission as well as other intervenors filed testimony responsive to the Application. The staff's testimony recommends that the Commission should either approve the projects with conditions or rule that it need not provide approval for the projects to proceed, while other intervenors range in their recommendations from suggesting that the Commission not approve the project to recommending outright approvals. Testimony has now also been received in Oklahoma and Arkansas. In Oklahoma both the staff and the Attorney General recommended approval of the projects and in Arkansas additional details were requested on the proposed projects. The Liberty Utilities Group's local regulatory teams continue to work closely with staffs and commissions from the regulatory agencies and anticipate securing approvals for the projects by June 2018.

CORPORATE DEVELOPMENT ACTIVITIES

The Corporate Development Group works to identify, develop and construct new power generating facilities as well as to identify and acquire operating projects that would be complementary and accretive to the Liberty Power Group's existing portfolio and the Company as a whole. The Corporate Development Group is focused on projects within North America and is committed to working proactively with all stakeholders including local communities.

The development and construction of new power generation facilities involves a number of risks and uncertainties including scheduling delays, cost over runs and other events that may be beyond the control of the Company (See *Operational Risk Management - Development and Construction Risk*).

The Corporate Development Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Corporate Development group will begin construction or execute an acquisition agreement.

Each of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and satisfaction of the Company's investment return objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost Range (millions)[1]	Commercial Operation	PPA Term (Years)	Production (GW-hrs)
Projects in Construction						
Amherst Island Wind Project	Ontario	75	$ 320 - $ 350	2018	20	235
Great Bay Solar Project[2]	Maryland	75	169 - 188	2018	10	146
Total Projects in Construction		**150**	**$ 489 - $ 538**			**381**
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	$ 315 - $ 350	2019/20	25	813
Val-Eo Wind Project[3]	Quebec	24	60 - 70	2018	20	66
Turquoise Solar Project[4]	Nevada	10	25 - 31	2018		28
Total Projects in Development		**211**	**$ 400 - $ 451**			**907**
Total in Construction and Development		**361**	**$ 889 - $ 989**			**1,288**

1 Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

2 The total cost of the project is expected to be approximately U.S. $135 - U.S. $150 million. Two of the four Great Bay Solar sites achieved COD in December 2017 while the remaining two sites are expected to achieve COD in the first quarter of 2018.

3 All figures refer solely to Phase I of the Val-Eo Wind Project.

4 The Turquoise Solar Project will be included in the rate base of the Calpeco Electric System (see *Regulatory Proceedings*). The total cost of the project is expected to be approximately U.S. $20.0 - U.S. $25.0 million.

Projects Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating development project located in central Michigan and is constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group.

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

The project is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to a local electric distribution utility which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

The Liberty Power Group's initial interest in the project was via a 50% joint venture with the original developer along with an option to acquire the other 50% interest. On March 14, 2017, the Liberty Power Group exercised its option and purchased the remaining 50% interest in the project for U.S. $21.6 million.

The project qualified for U.S. federal production tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $166.6 million of financing for the project was received from tax equity investors in May 2017.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Liberty Power Group's 20 MW Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualified for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $12.3 million of financing for the project was sourced from a tax equity investor. The tax equity financing closed on February 28, 2017, following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

Liberty Power's interest in the project is via a 50% joint venture. Liberty Power has an option to acquire the other 50% interest, subject to certain adjustments, after COD and prior to January 15, 2019.

The total costs to complete the project are estimated at approximately $320.0 million to $350.0 million. The increase in the expected range of construction costs are primarily the result of additional winter construction days than previously anticipated. As the Company refines its operating model for post COD, it has identified new operational costs savings of approximately $10.0 million which are expected to be realized over the life of the project. Construction over the fall and winter months has focused primarily on building access roads, foundations and receiving turbine components.

Manufacturing of major equipment is now complete and turbine deliveries commenced in November 2017, with all turbines expected to be delivered by March 2018. To date, two turbines have been erected and the foundation for the power transformer housing is complete. The main power transformer was delivered to the site in early February 2018. A 115kV submarine cable was also successfully installed during 2017. Subject to receipt of ongoing construction-related permitting, construction is expected to be substantially completed in the second quarter of 2018.

Placement of construction debt closed in the fourth quarter of 2017 with a consortium of major financial institutions for a total commitment of $260.4 million.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project comprised of four sites located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

The project received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission and building permits from the Somerset County Building and Zoning Department. Both the balance of plant and high voltage engineering, procurement, and construction contracts have been executed.

The total costs to complete the project are estimated at approximately U.S. $135.0 million to U.S. $150.0 million. The project achieved partial completion in late 2017, producing revenue on 25 MW of the full site capacity. Approximately U.S. $59.0 million of the permanent project financing will come from tax equity investors. As of December 31, 2017, the project has received U.S $42.8 million in project funding, with the remaining expected to be received in the first half of 2018.

Projects in Development

Blue Hill Wind Project

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan.

The project is expected to generate 813.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA originally awarded in 2012 and amended in 2016.

The project requires development permits as well as final environmental approval. The Environmental Impact Study was completed and submitted to the Saskatchewan Ministry of Environment in the fourth quarter of 2017. Stakeholder engagement continued through 2017 with relevant government officials, NGOs, landowners and the community through open houses and in-person meetings.

The total costs to complete the project are estimated at approximately $315.0 million to $350.0 million. SaskPower recently completed an interim system impact study for the wind turbine generators, which was received in the fourth quarter of 2017. A geotechnical evaluation of the project site and existing infrastructure began in the fourth quarter of 2017, with results expected in early 2018. Preparation and submission of the development permit is expected in the first quarter of 2018.

Val-Éo Wind Project

The Val-Éo Wind Project is a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec. The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Liberty Power Group.

The Liberty Power Group has a 50% economic equity interest in the project. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $16.0 million.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely comprise ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

The total costs to complete Phase I of the project are estimated at approximately $60.0 million to $70.0 million. All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

Turquoise Solar Project

The Turquoise Solar project is a 10 MW solar powered electric generating development project located in Washoe County in Nevada.

The facility is comprised of 108,000 solar thin film panels on a tracker system and is being constructed on 110 acres of land. The Turquoise Solar Project is expected to generate 28 GW-hrs of energy per year and to be included in the rate base of the Calpeco Electric System as energy produced from the project will be consumed by the utility's customers (see *Regulatory Proceedings*).

The project has been approved by the California PUC, and mechanical completion is expected in the fourth quarter of 2018.

The total costs to complete the project are estimated at approximately U.S. $20.0 million to U.S. $25.0 million. The Liberty Utilities Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 30% of the permanent financing is expected to be funded by tax equity investors.

APUC: CORPORATE AND OTHER EXPENSES

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Corporate and other expenses:				
Administrative expenses	**$ 18.7**	$ 13.1	**$ 64.5**	$ 46.3
(Gain)/Loss on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition facility related to the Empire Acquisition	**—**	18.2	**17.6**	57.6
Interest expense	**42.4**	20.5	**185.0**	74.0
Interest, dividend, equity, and other income[1]	**(0.6)**	(3.1)	**(2.8)**	(5.3)
Other losses (gains)	**4.7**	(0.8)	**0.6**	(11.8)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Income tax expense	**38.0**	11.5	**95.2**	37.1

[1] Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act ("U.S. Tax Reform" or the "Act"), was signed into law which resulted in significant changes to U.S. tax law. Key provisions of U.S. Tax Reform include the following:

- U.S. federal corporate income tax rate reduction from 35 per cent to 21 per cent effective January 1, 2018.
- The corporate alternative minimum tax ("AMT") is eliminated effective January 1, 2018.
- The Base Erosion Anti-Abuse Tax ("BEAT") is a new minimum tax computed each year and is generally the excess of (a) 10% of the taxpayer's "modified taxable income" over (b) the taxpayer's regular tax liability reduced by its tax credits.
- Other than for regulated utilities, interest deductibility is limited to 30 per cent of EBITDA from 2018 to 2021 and 30 per cent of EBIT after 2021.
- Other than for regulated utilities, immediate expensing of 100 per cent of the cost of new investments made in qualified depreciable assets after September 27, 2017.
- The production tax credit (the "PTC") of Section 45 of the Code and the investment tax credit (the "ITC") of Section 48 of the Code are left unchanged by the Act and the elimination of the AMT ensures that renewable energy tax credits will continue to be valuable to tax equity investors.
- The Act allows taxpayers until 2025 to offset any tax owed under the BEAT by 80% of the value of the PTCs and the ITCs for renewable energy projects.
- No change was made to the "continuous construction" requirement for determining when construction of a project commences.

As a result of these changes, the Company has remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. regulated and non-regulated businesses to reflect the new lower income tax rate as at December 31, 2017. This remeasurement resulted in a one-time non-cash accounting charge of $22.4 million and is recorded in the Company's 2017 consolidated statement of operations.

Future Impacts

Beginning in 2018, the Company expects its effective tax rate on consolidated worldwide net income to be below 20%.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company believes that most of its U.S. holding company interest can be properly allocable in accordance with the Act to its U.S. regulated utilities and is therefore largely exempted from the interest deductibility limitations.

It is expected there will be no material changes to the Company's U.S. regulated utilities' future net earnings, specifically as it pertains to U.S. Tax Reform since normal rate making processes would see the lower income tax expense and amortization of the deferred tax revaluation regulatory liability offset by lower customer rates over time. However, the Company believes that all stakeholders are best served by dealing with U.S. Tax Reform within the context of a full regulatory rate case proceeding, where all factors that comprise rates can be considered including investments in rate base, recovery of operating costs, capital structure and cost of capital.

APUC views that going forward the lower tax rates can enable accelerated investment over time in our regulated utilities to deliver an improved customer experience and more reliable service with less of an impact on customer rates than would otherwise occur.

APUC continues to believe that with the provisions in the Act for PTCs and ITCs, between the Company's ability to absorb a part of the renewable energy tax credits in future years and anticipated future demand from third party tax equity investors wishing to avail themselves of renewable energy tax credits, the Company will be able to satisfy the tax equity financing component for its U.S. renewable energy projects over the next three to five years.

SEC Guidance

The U.S. Securities and Exchange Commission ("SEC") has issued guidance allowing registrants to record provisional amounts which may be adjusted as information over time becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with tax laws in effect prior to the enactment of the Act.

At December 31, 2017, APUC considers all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Given that APUC's utility businesses are regulated, the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional information emerge that affects current estimates during this one-year measurement period allowed for by the SEC, adjustments will be made to the provisional amounts as appropriate.

2017 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2017, administrative expenses totaled $18.7 million as compared to $13.1 million in the same period in 2016. The $5.6 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the three months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $nil as compared to $18.2 million in the same period in 2016.

For the three months ended December 31, 2017, interest expense totaled $42.4 million as compared to $20.5 million in the same period in 2016. The interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups.

For the three months ended December 31, 2017, other losses were $4.7 million as compared to gains of $0.8 million in the same period in 2016. The increase in current period losses is primarily attributable to an increase in regulatory liabilities in the LPSCo Water System resulting from ongoing regulatory proceedings.

For the three months ended December 31, 2017, gains on derivative financial instruments totaled $4.0 million as compared to $12.9 million in the same period in 2016. The increase in 2016 was primarily driven by mark-to-market gains on foreign currency derivatives.

For the three months ended December 31, 2017, an income tax expense of $38.0 million was recorded as compared to an income tax expense of $11.5 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2017 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2017, administrative expenses totaled $64.5 million as compared to $46.3 million in the same period in 2016. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the twelve months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $17.6 million as compared to $57.6 million in the same period in 2016 (see *note 14* in the financial statements).

For the twelve months ended December 31, 2017, interest expense totaled $185.0 million as compared to $74.0 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups. (See *Credit Facilities & Debt* and *note 9* in the financial statements).

For the twelve months ended December 31, 2017, other losses were $0.6 million as compared to a gain of $11.8 million in the same period in 2016. The prior period gains primarily resulted from: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see *note 18* in the financial statements) partially offset by (iii) the write-down of the Company's equity interest in natural gas development projects that have been canceled by the developer.

For the twelve months ended December 31, 2017, acquisition-related costs totaled $62.8 million as compared to $12.0 million in the same period in 2016. The increase is primarily attributable to the Empire Acquisition.

For the twelve months ended December 31, 2017, the gain on derivative financial instruments totaled $2.6 million as compared to a gain of $15.8 million in the same period in 2016. The gain in 2016 was due to market-to-market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as derivatives.

An income tax expense of $95.2 million was recorded in the twelve months ended December 31, 2017 as compared to an income tax expense of $37.1 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition, the tax effect related to the Mountain Water condemnation, and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

NON-GAAP FINANCIAL MEASURES

Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to U.S. GAAP consolidated net earnings.

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.8**	(0.8)	**3.2**	7.5
Income tax expense	**38.0**	11.5	**95.2**	37.1
Interest expense on convertible debentures and bridge financing	**—**	18.2	**17.6**	57.6
Interest expense on long-term debt and others	**42.4**	20.5	**185.0**	74.0
Other losses (gains)	**4.8**	(0.8)	**0.7**	(11.9)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on energy derivative contracts	**—**	—	**(0.7)**	(1.0)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Depreciation and amortization	**88.0**	52.6	**326.4**	186.9
Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9

HLBV represents the value of net tax attributes earned during the period primarily from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2017 amounted to $14.3 million and $67.8 million as compared to $13.6 million and $41.0 million during the same period in 2016.

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with U.S. GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on derivative financial instruments	**—**	—	**(0.7)**	(1.0)
Loss (gain) on long-lived assets, net	**1.5**	(0.8)	**(2.5)**	(3.3)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition financing	**—**	18.2	**17.6**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Other adjustments	**3.2**	—	**3.2**	—
U.S. Tax Reform adjustment [2]	**22.4**		**22.4**	
Adjustment for taxes related to above	**(0.6)**	(3.1)	**(3.9)**	(18.4)
Adjusted Net Earnings	**$ 85.9**	$ 51.4	**$ 292.1**	$ 161.6
Adjusted Net Earnings per share[1]	**$ 0.20**	$ 0.18	**$ 0.74**	$ 0.57

1 Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

2 Represents the one-time non-cash accounting charge related to the revaluation of U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

For the three months ended December 31, 2017, Adjusted Net Earnings totaled $85.9 million as compared to Adjusted Net Earnings of $51.4 million for the same period in 2016, an increase of $34.5 million. The increase in Adjusted Net Earnings for the three months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

For the twelve months ended December 31, 2017, Adjusted Net Earnings totaled $292.1 million as compared to Adjusted Net Earnings of $161.6 million for the same period in 2016, an increase of $130.5 million. The increase in Adjusted Net Earnings for the twelve months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the consolidated statement of operations and consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with U.S GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

(all dollar amounts in $ millions)	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Cash flows from operating activities	**$ 169.8**	$ 121.9	**$ 457.8**	$ 287.9
Add (deduct):				
Changes in non-cash operating items	**(12.0)**	(46.7)	**74.0**	(3.7)
Production based cash contributions from non-controlling interests	**—**	0.6	**10.6**	11.2
Interest expense on convertible debentures and acquisition financing fees[1]	**—**	18.2	**9.3**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Cash generated from sale of long-lived assets	**—**	—	**—**	(8.6)
Adjusted Funds from Operations	**$ 159.1**	$ 96.4	**$ 614.5**	$ 356.4

[1] Exclusive of deferred financing fees of $8.3 million.

For the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million as compared to Adjusted Funds from Operations of $96.4 million for the same period in 2016, an increase of $62.7 million.

For the twelve months ended December 31, 2017, Adjusted Funds from Operations totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million for the same period in 2016, an increase of $258.1 million.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES[1]

(all dollar amounts in $ millions)	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Liberty Power Group:				
Maintenance	**$ 4.0**	$ 21.0	**$ 18.1**	$ 58.6
Investment in Capital Projects[1]	**17.1**	169.0	**592.7**	538.1
	$ 21.1	$ 190.0	**$ 610.8**	$ 596.7
Liberty Utilities Group:				
Rate Base Maintenance	**$ 58.4**	$ 27.0	**$ 222.1**	$ 102.7
Rate Base Acquisition	**—**	—	**2,764.4**	345.3
Rate Base Growth	**89.8**	101.0	**328.7**	163.4
	148.2	128.0	**3,315.2**	611.4
Total Capital Expenditures	**$ 169.3**	$ 318.0	**$ 3,926.0**	$ 1,208.1

[1] Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the Company.

2017 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $21.1 million as compared to $190.0 million during the same period in 2016. The capital expenditures include the ongoing construction of the Great Bay Solar Project, additional investment into the Amherst Wind Project, and ongoing maintenance capital at existing operating sites. Capital expenditures in the same quarter last year included the purchase of approximately $75 million of turbine components ("Safe Harbor Turbines"), costs of rebuilding the Donnaconna Hydro Facility dam, and ongoing development costs related to the investment and build of the Deerfield Wind, Amherst Wind, and Great Bay Solar Projects.

During the three months ended December 31, 2017, the Liberty Utilities Group invested $148.2 million in capital expenditures as compared to $128.0 million during the same period in 2016. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Capital expenditures in the same quarter last year included investments into the Luning Solar Facility and further development of Phase I of the North Lake Tahoe transmission project to upgrade the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2017 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $610.8 million as compared to $596.7 million during the same period in 2016. The capital expenditures include the acquisition of the remaining outstanding interest in the Deerfield Wind Facility, completion of the Bakersfield II Solar Facility, upgrade of the Tinker Transmission Facility, and ongoing development costs related to the investment and construction of the Amherst Wind and Great Bay Solar Projects.

During the twelve months ended December 31, 2017, the Liberty Utilities Group invested $3.3 billion in capital expenditures as compared to $611.4 million during the same period in 2016. The increase in capital expenditures is primarily due to the Empire Acquisition in January 2017 (U.S. $2.4 billion) and completion of the Luning Solar Facility located in Mineral County, Nevada in February 2017 (U.S. $84.9 million). In the prior year, the Liberty Utilities Group completed the acquisition of the Park Water System in January 2016, further development of Phase I of the North Lake Tahoe transmission project, and reliability enhancements, improvements and replenishment opportunities at the utility systems served.

2018 Capital Investments

In 2018, the Company plans to spend between $1.2 billion and $1.4 billion on capital investment opportunities. Actual expenditures during the course of 2018 may vary due to timing of various project investments and the realized U.S. dollar exchange rate.

Expected 2018 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Liberty Power Group:			
Maintenance	$ 30.0	-	$ 40.0
Investment in Capital Projects	120.0	-	150.0
Total Liberty Power Group:	$ 150.0	-	$ 190.0
Liberty Utilities Group:			
Rate Base Maintenance	$ 210.0	-	$ 230.0
Rate Base Growth	140.0	-	180.0
Total Liberty Utilities Group:	$ 350.0	-	$ 410.0
Investment in Atlantica[1]	$ 700.0		$ 800.0
Total 2018 Capital Investments	**$ 1,200.0**	**-**	**$ 1,400.0**

[1] See *Major Highlights*

The Liberty Power Group intends to spend between $150.0 million - $190.0 million over the course of 2018 to develop or further invest in capital projects, primarily in relation to the final development of the Great Bay Solar and Amherst Island Wind Projects. Additionally, the Liberty Power Group plans to spend $30.0 million - $40.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

The Liberty Utilities Group intends to spend between $350.0 million - $410.0 million over the course of 2018 in an effort to improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects entail spending capital for structural improvements, specifically in relation to drilling and equipping aquifers, main replacements, and reservoir pumping stations.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Power Group, and the Liberty Utilities Group to manage the liquidity and working capital requirements of each division (collectively the "Bank Credit Facilities").

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2017:

	As at December 31, 2017				As at Dec 31, 2016
(all dollar amounts in $ millions)	Corporate	Liberty Power	Liberty Utilities	Total	Total
Committed facilities	$ 165.0	$ 714.9	$ 501.8	**$ 1,381.7**	$ 773.8
Funds drawn on facilities	—	(44.8)	(16.3)	**(61.1)**	(242.9)
Letters of credit issued	(13.9)	(136.3)	(24.5)	**(174.7)**	(234.9)
Liquidity available under the facilities	**151.1**	**533.8**	**461.0**	**1,145.9**	296.0
Cash on hand				**54.6**	110.4
Total Liquidity and Capital Reserves	**$ 151.1**	**$ 533.8**	**$ 461.0**	**$ 1,200.5**	$ 406.4

As at December 31, 2017, the Company's $165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.9 million of outstanding letters of credit. The facility matures on November 19, 2018 and is subject to customary covenants.

On December 21, 2017, the Company entered into a U.S. $600.0 million term credit facility with two Canadian banks maturing on December 21, 2018. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the company drew U.S. $600.0 million under this facility.

As at December 31, 2017, the Liberty Power Group's committed bank lines consisted of a U.S. $500.0 million senior unsecured syndicated revolving credit facility and a $87.6 million letter of credit facility (Cdn $50.0 million and U.S. $30.0 million). As at December 31, 2017, the group had drawn $44.8 million and had $136.3 million in outstanding letters of credit. The facilities mature on October 6, 2022 and October 30, 2018, respectively. Subsequent to year-end, on February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200.0 million and extended the maturity to January 31, 2021. The expansion of both the revolving credit and letter of credit facility further increases the Liberty Power Group's ability to support the cash needs of its development portfolio.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200.0 million senior unsecured syndicated revolving credit facility at the holding company ("Liberty Credit Facility") and a U.S. $200.0 million revolving credit facility at Empire ("Empire Credit Facility"). The credit facilities mature on September 30, 2018 and October 20, 2019, respectively. The Empire Credit Facility is used primarily as a backstop to commercial paper issued by Empire. As at December 31, 2017, the Liberty Utilities Group had drawn a total of $16.3 million (U.S. $13.0 million) and had $24.5 million (U.S. $19.5 million) of outstanding letters of credit. Subsequent to year-end on February 23, 2018, the Liberty Utilities Group increased commitments under the Liberty Credit Facility to U.S. $500.0 million and extended the maturity to 2023. In conjunction with the increase to the Liberty Credit Facility, the Empire Credit Facility was canceled. The Liberty Credit Facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire as required.

On February 9, 2016, in connection with the Empire Acquisition, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. On December 30, 2016, the Company drew U.S. $1,336.4 million on the Acquisition Facility in connection with the closing of the Empire Acquisition. The Acquisition Facility was fully repaid in the first quarter of 2017 from proceeds received from the final installment payment, the Liberty Private Placement (discussed below) and general corporate funds.

Long Term Debt

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750.0 million of senior unsecured notes ("Liberty Private Placement") in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "*Interest Rate Risk*"). Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group is 3.6%. The proceeds of the offering were applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at December 31, 2017, the weighted average tenor of APUC's total long term debt is approximately 12 years with an average interest rate of 4.6%.

Convertible Unsecured Subordinated Debentures

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures of APUC.

All Debentures were sold on an instalment basis at a price of $1,000 dollars per debenture, of which $333 dollars was paid on the closing of the Offering and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of the Empire Acquisition (the "Final Instalment Date"), at which time each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

The final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of the Acquisition Facility. As at March 6, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

Contractual Obligations

Information concerning contractual obligations as of December 31, 2017 is shown below:

(all dollar amounts in $ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1]	**$ 3,826.1**	$ 279.7	$ 570.1	$ 645.0	$ 2,331.3
Convertible debentures	**1.2**	—	—	—	1.2
Advances in aid of construction	**78.6**	1.5	—	—	77.1
Interest on long-term debt obligations	**2,006.2**	172.7	307.5	250.8	1,275.2
Purchase obligations	**501.9**	501.9	—	—	—
Environmental obligations	**72.0**	7.8	18.9	5.4	39.9
Derivative financial instruments:					
Cross currency swap	**72.0**	4.4	8.1	64.7	(5.2)
Interest rate swap	**10.6**	10.6	—	—	—
Currency forward	**0.4**	0.4	—	—	—
Energy derivative and commodity contracts	**3.4**	2.3	1.0	—	0.1
Purchased power	**527.4**	74.0	98.3	100.7	254.4
Gas delivery, service and supply agreements	**369.2**	91.4	118.7	61.6	97.5
Service agreements	**673.9**	47.7	95.7	95.4	435.1
Capital projects	**58.3**	41.1	17.1	0.1	—
Operating leases	**270.0**	9.6	17.3	18.1	225.0
Other obligations	**155.3**	45.0	—	—	110.3
Total Obligations	**$ 8,626.5**	**$ 1,290.1**	**$ 1,252.7**	**$ 1,241.8**	**$ 4,841.9**

1 Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2017, APUC had 431,765,935 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2017, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of common shares of APUC. As at December 31, 2017, 94,049,616 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2017, 3,905,848 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 12, 2018, an additional 1,063,572 common shares were issued under the Reinvestment Plan.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2017, APUC recorded $10.8 million in total share-based compensation expense as compared to $5.7 million for the same period in 2016. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were $2.8 million and $8.5 million, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2017, the Company granted 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $12.82, the market price of the underlying common share at the date of grant. In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of $7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2017, a total of 6,738,856 options are issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2017, the Company granted (including dividends and performance adjustments) 811,974 PSUs to executives and employees of the Company. During the year, the Company settled 374,973 PSUs, of which 183,035 PSUs were exchanged for common shares issued from treasury and 191,938 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2017, a total of 60,961 PSUs were forfeited.

As at December 31, 2017, a total of 955,028 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2017, the Company issued 69,243 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2017, a total of 293,906 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2017, the Company issued 283,523 common shares to employees under the ESPP.

As at December 31, 2017, a total of 779,553 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Emera Inc.

An executive at Emera Inc. ("Emera") was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4.4 million as compared to U.S. $10.2 million during the same period in 2016. The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during 2017 amounts to U.S. $1.0 million as compared to U.S. $3.9 million during the same period in 2016. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.

In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in the second quarter of 2017, with the final completion of the contract work in the fourth quarter of 2017. The total cost of the contract was $9.5 million. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1.5 million included in accruals in 2017 as compared to U.S. $0.8 million during the same period in 2016 related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $6.0 million in 2017 as compared to $3.3 million during the same period in 2016.

Trafalgar

In 2016, the Company received U.S. $10.1 million in proceeds from the settlement of the Trafalgar matter and paid U.S. $2.9 million to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

ENTERPRISE RISK MANAGEMENT

The Corporation is subject to a number of risks and uncertainties. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation's business could be materially different from what is anticipated. The description of risks below does not include all possible risks.

An enterprise risk management, or "ERM", framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as the Corporation's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee on a quarterly basis.

Risks are evaluated consistently across the organization using a common risk scoring matrix to assess impact and likelihood. Financial, reputational, and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of the Corporation's strategic and business plans.

The development and execution of risk treatment plans for the organization's top risks are actively monitored by the Company's senior leadership team and Board of Directors. The Corporation's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for key risks. Audit findings are discussed with business owners and reported to the Audit Committee of the Board of Directors on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, the Corporate Governance and Risk Committees, and the Board of Directors of the Corporation for consideration.

The Corporation's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that the Corporation's risk appetite is thoroughly considered in decision-making across the organization

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is set out in the Company's most recent AIF available on SEDAR.

Treasury Risk Management

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's.

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries' issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long-term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

The Company is not adopting or endorsing such ratings, and such ratings do not indicate APUC's assessment of its own ability to pay the interest or principal of debt securities it issues. The Company is providing such ratings only to assist with the assessment of future risks and effects of ratings on the Company's financing costs.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

Capital Markets and Liquidity Risk

As of December 31, 2017, the Company had approximately $3,864.5 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favorable terms may be affected by the Company's financial and operational performance, and by financial market disruptions or other factors outside the control of the Company.

In addition, the Company may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the degree of the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; limit the Company's ability to declare dividends on its common shares; require the Company to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose the Company to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place the Company at a competitive disadvantage compared to its competitors that have less debt; make the Company vulnerable to any downturn in general economic conditions; and render the Company unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favorable than the current terms, the ability of the Company to declare dividends may be adversely affected.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flows in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to significant interest rate risk in the short to medium term time horizon.

Borrowings subject to variable interest rates can vary significantly from month to month, quarter to quarter and year to year. APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Based on amounts outstanding as at December 31, 2017, the impact to interest expense from changes in interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had $44.8 million outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $0.4 million annually;
- The Liberty Utilities Group's revolving credit facilities are subject to a variable interest rate and had $16.3 million outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $7.0 million (U.S. $5.6 million) outstanding at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually.
- The Corporate Term Facility is subject to a variable interest rate and had $169.4 million (U.S. $135.0 million) outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 million annually;

To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Liberty Power Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.

Foreign Currency Risk

Currency fluctuations may affect the Canadian dollar equivalent cash flows that APUC realizes from its consolidated operations because a significant portion of the Company's revenues are generated through APUC subsidiary businesses which sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 93% of Adjusted EBITDA in 2017 and 93% of cash flow from operations is generated in U.S. dollars.

APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $82.3 million ($0.22 per share) on an annual basis. In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

APUC may enter into derivative contracts to hedge all or a portion of currency exchange rate exposure that is transactional in nature and where a natural economic hedge does not exist. To the extent that the Company does enter into currency hedges, the Company may not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts.

Effective the first quarter of 2018, APUC will begin to report its results in U.S. dollars.

Tax Risk and Uncertainty

The Company is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which APUC does business could adversely affect the Company's results from operations, our return to shareholders, and cash flow.

The Company cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Company, including with respect to claimed expenses and the cost amount of the Company's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or APUC is unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that APUC is committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Company from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Company (See *U.S. Tax Reform*).

Credit/Counterparty Risk

APUC and its subsidiaries, through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments, are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

Liberty Power Group's revenues are approximately 15% of total Company revenues. Approximately 94% of the Liberty Power Group's revenues are earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. The following chart sets out the Liberty Power Group's customers representing greater than 5% of total Liberty Power Group revenues and their credit ratings:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percentage of Liberty Power Group Revenue
PJM Interconnection LLC	Aa2	$ 31.8	11.2%
Manitoba Hydro	Aa2	30.3	10.7%
Hydro Quebec	Aa2	29.1	10.3%
Commonwealth Edison	A3	26.4	9.3%
Xcel Energy	A3	24.2	8.6%
Pacific Gas and Electric Company	A3	24.1	8.5%
Wolverine Power Supply	A	23.5	8.3%
Ontario Electricity Financial Corporation	Aa2	22.9	8.1%
Electric Reliability Council of Texas (ERCOT)	Aa3	16.7	5.9%
Connecticut Light and Power	Baa1	16.2	5.7%
Total		**$ 245.2**	

[1] Ratings by DBRS, Moody's, or S&P.

The remaining revenue of the Company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $10.4 million which is spread over approximately 160,000 connections, resulting in an average outstanding balance of approximately U.S. $70 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $21.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $99.9 million. The natural gas and electrical utilities both derive over 84% of their revenue from residential customers.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Liberty Power Group is unable to perform, the Liberty Power Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

Market Price Risk

The Liberty Power Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Liberty Power Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Liberty Power Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Liberty Power Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the Liberty Power Group along with residual exposures to the market are detailed below:

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

A second hedge for the Sandy Ridge Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 73% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 42,000 MW-hrs annually.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

A second hedge for the Minonk Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 72% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 189,000 MW-hrs annually.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Liberty Power Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2017, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,080 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $0.5 million for the year.

Commodity Price Risk

The Liberty Power Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 181,000 MW-hrs in fiscal 2018, of which 170,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 37,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 181,000 MW-hrs. The risk associated with the expected market purchases of 37,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 20% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $86 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

The Calpeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The Calpeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The Calpeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the Calpeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the Georgia PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 58% of its 2017 generation fuel supply need through coal. Approximately 97% of its 2017 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts and inventory on hand satisfy approximately 56% of anticipated fuel requirements for 2018 for the Asbury Coal Facility.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel adjustment clause and PGA filings and are embedded in the approved rates in such filings.

OPERATIONAL RISK MANAGEMENT

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, natural disasters, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Liberty Power Group's hydro assets utilize dams to pond water for generation and if the dams fail/breach potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Liberty Power Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions, which will lower wind levels below our PPA and hedge minimum production levels. The wind units can experience failures in the turbine blades or in the supporting towers. Production risks associated with the wind turbine generators failures is mitigated by properly maintaining the units, using long term maintenance agreements with the turbine O&Ms which provide for regular inspections and maintenance of property, and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Liberty Power Group's Thermal Energy Division uses natural gas and oil, and produces exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the thermal facilities are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged in part by long term purchases.

All of the Liberty Power Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Liberty Utilities Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Liberty Utilities Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down, with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Liberty Utilities Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance, an active Enterprise Risk Management program and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The Liberty Utilities Group operates in 12 different states and therefore is subject to regulation from 12 different regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Liberty Utilities Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, the Act reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates will have a significant impact on the financial operations and regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. The Liberty Utilities Group is working with stakeholders to understand the full implications and impact of the new law. Liberty believes that customers will be best served by dealing with Tax Reform within the context of a full regulatory rate case, where all factors that comprise rates can be considered.

Condemnation Expropriation Proceedings

The Liberty Utilities Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

Mountain Water Condemnation Proceedings

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("Carlyle"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. $88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have appealed certain elements of the final order of condemnation including, among other issues, recovery of post-summons interest and attorney's fees.

Apple Valley Condemnation Proceedings

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to require a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act ("CEQA") lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Apple Valley's CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case on March 6, 2018 to potentially set a trial date on the first phase of the condemnation action.

Acquisition Risk

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

When acquisitions occur, significant demands can be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Joint Venture Investment Risk

Certain development and operating entities that the Company has interest in are jointly owned with third parties. The Company may not have the sole discretion or ability to affect the management or operations at such facilities and thereby may not be able to make determinations on how to manage these facilities in light of changing economic circumstances. A divergence in the interests of the Company and the co-owners could negatively impact the realization of the Company's investment in the joint venture business, which may have a disproportionate economic impact relative to the Company's investment.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Liberty Utilities Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Liberty Utilities Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Liberty Utilities Group expects to be allowed to earn a return on such investment.

In conjunction with acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas mains when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

Cycles and Seasonality

Liberty Power Group

The Liberty Power Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Liberty Power Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Liberty Utilities Group

The Liberty Utilities Group's demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Liberty Utilities Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 4 of 12 states representing approximately 25% of customers. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. The Liberty Utilities Group is presently seeking weather related decoupling mechanism for its utilities in Missouri and New Hampshire.

Development and Construction Risk

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

Risks Specific to Renewable Generation Projects:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal and regulatory proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

See further discussion of claims made by or against APUC or its subsidiaries in *Regulatory Risk*.

Cybersecurity Risk

The Company's information technology systems may be vulnerable to potential risks from cybersecurity attacks. Attacks can be caused by malware, viruses, email attachments, acts of war or terrorism and can originate from individuals from both inside and outside the organization. An attack could result in service disruptions, system failures, the disclosure of personal customer and employee information, and could lead to an adverse effect on the Company's financial performance. A breach of personal or confidential information may also occur as a result of non-cyber means, such as breach of physical security. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

The Company mitigates these risks by maintaining a cybersecurity program that is overseen by the Board of Directors, and executed by a cross functional management team. The program is intended to provide adequate controls for the appropriate protection of critical business systems. These controls have been put into place to mitigate potential risks, and to improve the organization’s capability to respond and recover from any potential cyber incident.

Energy Consumption and Advancement in Technologies Risk

The Liberty Utilities Group's operations are subject to changes in demand for energy which are impacted by general economic conditions, customer's focus on energy efficiency, and advancements in new technologies.

The Liberty Utilities Group is actively involved in working with governments and customers to ensure these changes in consumption do not negatively impact the services provided. Furthermore, through its strategic initiatives the Liberty Utilities Group is constantly looking for ways to maintain the Company's competitive advantage.

Uninsured Risk

The Company maintains insurance for accidental loss and potential liabilities to third parties. However, there are certain elements of the Liberty Utilities Group's regulated utilities that are not fully insured as the cost of the coverage is not economically viable. In the event that a liability event or loss is not covered through insurance the Liberty Utilities Group would apply to their respective regulator to request recovery through increased customer rates. Cost recovery through this mechanism is subject to regulatory approval and is therefore uncertain.

Insurance coverage for the rest of the Company is also subject to policy conditions and exclusions, coverage limits, and various deductibles, and not all types of liabilities and losses may be covered by insurance, in which case the Company may be financially exposed.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2017:

(all dollar amounts in $ millions except per share information)	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017	4th Quarter 2017
Revenue	$ 557.9	$ 453.2	$ 443.3	$ 523.4
Net earnings attributable to shareholders	26.0	47.7	59.4	60.0
Net earnings per share	0.07	0.12	0.15	0.14
Adjusted Net Earnings	88.1	53.3	64.9	85.9
Adjusted Net Earnings per share	0.25	0.13	0.16	0.20
Adjusted EBITDA	254.8	197.6	197.5	233.4
Total assets	10,880.7	10,528.6	10,306.7	10,533.6
Long term debt[1]	4,773.6	4,418.0	4,435.1	3,864.5
Dividend declared per common share	$ 0.15	$ 0.16	$ 0.15	$ 0.15

	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016
Revenue	$ 341.7	$ 222.8	$ 221.3	$ 310.2
Net earnings attributable to shareholders	42.0	24.8	17.7	46.3
Net earnings per share	0.15	0.08	0.06	0.16
Adjusted Net Earnings	56.1	30.9	26.6	51.4
Adjusted Net Earnings per share	0.21	0.11	0.09	0.18
Adjusted EBITDA	147.9	99.2	91.4	138.3
Total assets	5,615.5	5,555.0	6,020.8	8,249.5
Long term debt[1]	2,214.5	2,199.9	2,380.8	4,272.0
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14

[1] Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $221.3 million and $557.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.7 million and $60 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2017, under the supervision of and with the participation of APUC's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2017, APUC's disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by APUC in reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

During the year ended December 31, 2017, the Company acquired Empire. Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company's internal control over financial reporting. The financial information for this acquisition is included in this MD&A and in *note 3* to the consolidated financial statements. As permitted by National Instrument 52-109 and the SEC, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and approximately 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of APUC.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

For the twelve months ended December 31, 2017, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. The Company continues to implement its internal control structure over the operations of the acquired business discussed above.

INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

Due to its inherent limitations, disclosure controls and procedures or internal control over financial reporting may not prevent or detect all misstatements based on error of fraud. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, the measurement of deferred taxes and the recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies and new accounting standards are discussed in *notes 1* and *2* to the consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

A recoverability analysis was performed in 2017 for wind generating assets operating without a PPA and in 2016 for wind and small hydro generating assets without a PPA. No impairment provision was required in 2017 or 2016. A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2017 and 2016, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

Measurement of Deferred Taxes

On December 22, 2017, the U.S. government enacted the Tax Cuts and Jobs Act (the "Act"). The Act made broad and complex changes to the U.S. tax code which impacted 2017 including, but not limited to, reducing the U.S. federal corporate tax rate from 35% to 21% and introducing 100% expensing for certain capital expenditures, excluding regulated utilities, made after September 27, 2017. Management's judgment is required to measure the deferred taxes assets and liabilities at the enactment date based on these changes. Where requirements of the implementation of the new Act are incomplete, management uses judgments and assumptions to calculate a reasonable provisional amount to include in the Company's financial statements.

Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Although at this time Management considers it more likely than not that it will have sufficient taxable income to realize the deferred tax assets, there can be no assurance that the company will generate sufficient taxable income in the future to utilize these deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. Management's assessment has been impacted by the tax reform discussed above.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Liberty Utilities Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The Financial Accounting Standards Board ("FASB") issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. The Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company intends to adopt the new revenue recognition standard using the modified retrospective method effective January 1, 2018.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management’s judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management’s judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC’s results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2017) recently released by the Society of Actuaries adjusted to reflect the 2017 Social Security Administration ultimate improvement rates.

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, for reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this Accounting Standards Update ("ASU"), the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2017 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

	2017 Pension Plans		2017 OPEB Plans	
(all dollar amounts in $ millions)	Accrued Benefit Obligation	Net Periodic Pension Cost	Accumulated Postretirement Benefit Obligation	Net Periodic Postretirement Benefit Cost
Discount Rate				
1% increase	(65.6)	(4.4)	(31.5)	(1.9)
1% decrease	81.1	6.7	39.7	2.1
Future compensation rate				
1% increase	0.2	1.5	—	—
1% decrease	(0.2)	(1.3)	—	—
Expected return on plan assets				
1% increase	—	(4.5)	—	(1.4)
1% decrease	—	4.5	—	1.4
Life expectancy				
10% increase	38.0	3.3	19.7	1.6
10% decrease	(39.9)	(2.8)	(18.8)	(1.8)
Health care trend				
1% increase	—	—	38.0	4.3
1% decrease	—	—	(30.1)	(3.3)

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC's critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our Firm under the caption "Interest of Experts" and to the use in this Annual Report on Form 40-F filed with the United States Securities and Exchange Commission of our reports dated March 7, 2018, with respect to the consolidated balance sheets of Algonquin Power and Utilities Corp. (the "Company") as at December 31, 2017 and 2016, and the consolidated statements of operations, comprehensive income/(loss), equity, and cash flows for each of the years in the two-year period ended December 31, 2017, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2017.

We also consent to the incorporation by reference of our reports dated March 7, 2018 in the Registration Statements on Form S-8 (No. 333-177418), Form S-8 (File No. 333-213650), Form S-8 (File No. 333-213648), Form S-8 (File No. 333-218810), Form F-10 (No. 333-216616) and Form F-3D (No. 333-220059), with respect to the consolidated balance sheets of the Company as at December 31, 2017 and 2016, and the consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the two-year period ended December 31, 2017, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2017.

/s/ "Ernst & Young LLP"
Chartered Professional Accountants,
Licensed Public Accountants

Toronto, Canada
March 7, 2018

Exhibit 99.5

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 7, 2018	By:	/s/ Ian E. Robertson
	Name:	Ian E. Robertson
	Title:	Chief Executive Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 7, 2018	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer

Exhibit 99.7

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the “Corporation”) on Form 40-F for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 7, 2018	By:	/s/ Ian Robertson
	Name:	Ian E. Robertson
	Title:	Chief Executive Officer

Exhibit 99.8

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the “Corporation”) on Form 40-F for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 7, 2018	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of

Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of The Empire District Electric Company, which comprise the consolidated balance sheet as at December 31, 2017, and the consolidated statements of income, common stockholder's equity and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of The Empire District Electric Company as at December 31, 2017, and the results of its operations and its cash flows for the year then ended in conformity with United States generally accepted accounting principles.

Other Matter

The financial statements of The Empire District Electric Company for the year ended December 31, 2016, were audited by another auditor who expressed an unmodified opinion on those statements in accordance with United States generally accepted auditing standards on February 15, 2017.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
March 29, 2018

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Balance Sheets

	December 31, 2017	December 31, 2016
	($000s)	
Assets		
Plant and property, at original cost:		
Electric	$ 2,801,273	$ 2,726,264
Gas	89,623	87,071
Other	44,707	45,181
Construction work in progress	32,711	29,022
	2,968,314	2,887,538
Accumulated depreciation and amortization	870,634	823,287
	2,097,680	2,064,251
Current assets:		
Cash and cash equivalents	1,360	1,742
Restricted cash	4,736	4,728
Accounts receivable – trade, net of allowance of $530 and $460, respectively	48,417	43,859
Accrued unbilled revenues	23,277	24,997
Accounts receivable – other	13,038	4,063
Fuel, materials and supplies	60,162	56,047
Prepaid expenses and other	9,627	9,894
Unrealized gain in fair value of derivative contracts	6,247	6,041
Regulatory assets	19,339	8,390
	186,203	159,761
Noncurrent assets and deferred charges:		
Regulatory assets	186,118	212,085
Goodwill	39,492	39,492
Unrealized gain in fair value of derivative contracts	53	684
Other	6,710	3,008
	232,373	255,269
Total assets	**$ 2,516,256**	**$ 2,479,281**

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Balance Sheets

	December 31, 2017	2016
	($000s)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 43,993,363 and 44,177,535 shares issued and outstanding, respectively	$ 43,993	$ 44,178
Capital in excess of par value	663,018	667,953
Retained earnings	120,500	115,766
Total common stockholder's equity	827,511	827,897
Long-term debt (net of current portion)		
Obligations under capital lease	2,838	3,250
First mortgage bonds and secured debt	726,106	725,472
Unsecured debt	101,050	100,993
Total long-term debt	829,994	829,715
Total long-term debt and common stockholder's equity	1,657,505	1,657,612
Current liabilities:		
Accounts payable and accrued liabilities	86,497	53,941
Current maturities of capital lease obligations	369	329
Short-term debt	5,575	24,750
Regulatory liabilities	4,491	14,506
Customer deposits	15,869	15,440
Interest accrued	7,210	7,198
Unrealized loss in fair value of derivative contracts	1,486	1,143
Taxes accrued	5,440	3,176
Dividends declared	-	3,896
Other current liabilities	160	220
	127,097	124,599
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	324,812	136,024
Deferred income taxes	277,013	429,666
Unamortized investment tax credits	17,734	18,077
Pension and other postemployment benefit obligations	74,393	78,272
Unrealized loss in fair value of derivative contracts	709	1,239
Other	36,993	33,792
	731,654	697,070
Total capitalization and liabilities	**$ 2,516,256**	**$ 2,479,281**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Statements of Income

	Year Ended December 31, 2017	2016
	($000s, except per share amounts)	
Operating revenues:		
Electric	$ 584,767	$ 568,766
Gas	35,998	36,743
Other	6,254	7,041
	627,019	612,550
Operating revenue deductions:		
Fuel and purchased power	134,258	154,430
Cost of natural gas sold and transported	14,798	15,180
Regulated operating expenses	121,952	114,129
Other operating expenses	2,893	3,254
Maintenance and repairs	47,608	46,530
Merger related expenses	42,098	9,082
Depreciation and amortization	85,538	86,006
Other taxes	39,539	37,918
	488,684	466,529
Operating income	138,335	146,021
Other income(deductions):		
Allowance for equity funds used during construction	883	3,208
Interest income	270	130
Other – non-operating expense, net	(1,434)	(1,857)
	(281)	1,481
Interest charges:		
Long-term debt	43,324	45,038
Short-term debt	115	120
Allowance for borrowed funds used during construction	(560)	(1,928)
Other	1,143	1,140
	44,022	44,370
Income before tax	94,032	103,132
Provision for income taxes	57,298	39,105
Net income	**$ 36,734**	**$ 64,027**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Statements of Common Stockholder's Equity

	Common Stock	Capital in Excess of Par	Retained Earnings	Total
		($000s)		
Balance at December 31, 2015	$ 43,821	$ 657,466	$ 101,443	$ 802,730
Net income	-	-	64,027	64,027
Stock/stock units issued through:				
Stock purchase and reinvestment plans	357	10,487	-	10,844
Dividends declared	-	-	(49,704)	(49,704)
Balance at December 31, 2016	44,178	667,953	115,766	827,897
Net income	-	-	36,734	36,734
Stock/stock units issued through:				
Stock purchase and reinvestment plans	(185)	(4,935)	-	(5,120)
Dividends declared	-	-	(32,000)	(32,000)
Balance at December 31, 2017	**$ 43,993**	**$ 663,018**	**$ 120,500**	**$ 827,511**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Statements of Cash Flows

	Year Ended December 31, 2017	2016
	($000s)	
Operating activities:		
Net income	$ 36,734	$ 64,027
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization including regulatory items	87,464	83,723
Pension and other postemployment benefit costs, net of contributions	16,548	1,946
Deferred income taxes and unamortized investment tax credit, net	54,991	38,366
Allowance for equity funds used during construction	(883)	(3,208)
Stock-based compensation expense	(85)	6,448
Non-cash loss on derivatives	2,540	2,428
Other	251	95
Cash flows impacted by changes in:		
Accounts receivable and accrued unbilled revenues	(14,353)	7,296
Fuel, materials and supplies	(4,115)	4,903
Prepaid expenses, other current assets and deferred charges	(28,680)	(18,190)
Accounts payable and accrued liabilities	18,226	(13,552)
Asset retirement obligation	(2,811)	(384)
Interest, taxes accrued and customer deposits	4,592	1,011
Other liabilities and other deferred credits	486	11,374
Net cash provided by operating activities	170,905	186,283

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
A Liberty Utilities Company
Consolidated Statements of Cash Flows

	Year Ended December 31, 2017	2016
	($000s)	
Investing activities:		
Capital expenditures – regulated	$ (115,993)	$ (121,462)
Capital expenditures and other investments – non-regulated	(1,071)	(938)
Accounts receivable due from parent	1,676	-
Restricted cash	(8)	(2)
Net cash used in investing activities	(115,396)	(122,402)
Financing activities:		
Return of employee stock purchase plan equity rights upon merger	(448)	-
Repayment of first mortgage bonds	-	(25,000)
Proceeds from issuance of common stock, net of issuance costs	-	7,476
Net short-term borrowings (repayments)	(19,175)	(250)
Dividends	(35,896)	(45,808)
Other	(372)	(310)
Net cash used in financing activities	(55,891)	(63,892)
Net decrease in cash and cash equivalents	(382)	(11)
Cash and cash equivalents, beginning of year	1,742	1,753
Cash and cash equivalents, end of year	**$ 1,360**	**$ 1,742**

	2017	2016
Supplemental cash flow information:		
Interest paid	$ 43,094	$ 44,938
Income taxes (refunded) paid, net of refund	10	(7,441)
Supplementary non-cash investing activities:		
Change in accrued additions to property, plant and equipment not reported above	$ 6,277	$ (3,134)
Capital lease obligations for purchase of new equipment	$ 71	$ -

The accompanying notes are an integral part of these consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Pursuant to an Agreement and Plan of Merger (“the Merger Agreement”), dated as of February 9, 2016, by and among The Empire District Electric Company (“Empire” or “EDE”), Liberty Utilities (Central) Co. (“Liberty Central”) (an indirect subsidiary of Algonquin Power & Utilities Corp. (“Algonquin” or “APUC”)) and Liberty Sub Corp. (“Merger Sub”), a wholly owned direct subsidiary of Liberty Central, Merger Sub merged with and into Empire, with Empire surviving the merger and becoming a wholly owned direct subsidiary of Liberty Central (“the Merger”). The Merger closed effective January 1, 2017 (“the Closing Date”). As a result, effective with the closing of the Merger, Empire ceased to be a publicly-held corporation and Empire common stock ceased trading on the New York Stock Exchange. Since Merger Sub had nominal net assets and, since Empire did not apply pushdown accounting related to Liberty Central’s acquisition of Empire under ASU 2014-17, the Merger did not have any impact on the financial statements of Empire other than Merger-related expenses. See Note 15 for further discussion of the Merger Agreement.

We operate our businesses as three segments: electric, gas and other. Empire, a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business (See Note 12). Our gross operating revenues in 2017 were derived as follows:

Electric segment sales*		93.3%
On-system revenues	85.7 %	
SPP IM revenues	5.3	
Other revenues	2.0	
Gas segment sales		5.7
Other segment sales		1.0

*Sales from our electric segment include 0.3% from the sale of water.

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the rate-making practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 172,800 customers as of December 31, 2017, and the 2017 electric operating revenues were derived as follows:

Customer Class	% of revenue
Residential	40.9%
Commercial	30.1
Industrial	15.2
Wholesale on-system	3.3
Wholesale off-system	5.7
Miscellaneous sources, primarily public authorities	2.7
Other electric revenues	2.1

Our retail electric revenues for 2017 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	90.1 %
Kansas	4.5
Oklahoma	2.5
Arkansas	2.9

Our gas operations serve approximately 43,400 customers as of December 31, 2017, and the 2017 gas operating revenues were derived as follows:

Customer Class	% of revenue
Residential	62.9%
Commercial	24.5
Industrial	0.6
Transportation	10.2
Miscellaneous	1.8

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as “we” or “the Company”. All intercompany balances and transactions have been eliminated in consolidation. See Note 12 for additional information regarding our three segments. Certain immaterial reclassifications have been made to prior year information to conform to the current year presentation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (US GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the consolidated financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectability of accounts receivable, depreciable lives, asset impairments and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock-based compensation, and tax provisions. Actual amounts could differ from those estimates.

Accounting for the Effects of Regulation

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our consolidated financial statements reflect rate-making policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which says that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for rate-making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also indicates that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal rate-making procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We generally include amortization of regulatory assets and liabilities in the depreciation and amortization line of our consolidated statement of cash flows. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. See Note 3 for further discussion of regulatory assets and liabilities.

Revenue Recognition

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period-end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes.

Municipal Franchise Taxes

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the consolidated statements of income. Municipal franchise taxes of $11.4 million and $11.1 million were recorded for each of the years ended December 31, 2017 and 2016, respectively.

Accounts Receivable

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of regulated units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years, we refund to the developer a pro-rata amount of the original cost of the extension for each new customer added to the extension. Nonrefundable payments at the end of the five-year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2017 and 2016 was $2.9 million and $2.4 million, respectively.

Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful lives of the properties. See Note 2 for additional details regarding depreciation rates.

As of December 31, 2017 and 2016, we had recorded accrued cost of removal of $87.8 million and $88.2 million, respectively, for our electric operating segment. This amount, recorded as a regulatory liability, represents an estimated future cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. We accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We have a similar cost of removal regulatory liability for our gas operating segment. This amount accrued at December 31, 2017 and 2016 was $11.2 million and $10.0 million, respectively. These amounts are net of our actual cost of removal expenditures.

Asset Retirement Obligation (ARO)

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have asset retirement obligations associated with the removal of asbestos located at the Asbury Power Plant, the closure of a solid waste landfill at the Plum Point Energy Station, and closure of existing coal combustion residual (CCR) impoundments at our Asbury Power Plant and Iatan Generating Station. During 2016, the liability for the CCR impoundment at our Asbury Power Plant was re-evaluated and increased by $8.2 million based on updated cost estimates. During 2017, the liabilities for the solid waste landfill at the Plum Point Energy Station and the CCR impoundment at the Asbury Power Plant were revised to reflect new cost estimates and changes in the expected timing of the future cash flows. These changes increased the ARO obligation by approximately $0.1 million. The obligation related to the removal of asbestos at our Riverton Power Plant was revised upward by approximately $1.0 million to reflect the expected timing of its settlement. During 2017, the necessary asbestos remediation work was completed at our Riverton Power Plant and the related asset retirement obligation was settled.

In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third-party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third-party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 1.93% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements.

The balances at the end of 2017 and 2016, recorded in other liabilities, are shown below.

(000's)	Liability Balance at 12/31/16	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/17
Asset retirement obligation	$ 23,545	$ -	$ (4,174)	$ 808	$ 1,137	$ 21,316

(000's)	Liability Balance at 12/31/15	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/16
Asset retirement obligation	$ 15,072	$ -	$ (385)	$ 684	$ 8,174	$ 23,545

Upon adoption of the standards on the retirement of long-lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2017 and 2016, our regulatory assets relating to asset retirement obligations totaled $16.1 million and $11.3 million, respectively.

Allowance for Funds Used During Construction

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to construction programs are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates of 5.5% for 2017 and 6.5% for 2016, compounded semiannually.

Asset Impairments (excluding goodwill)

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to assess the recoverability of the assets and, if necessary, the fair value is determined to measure the impairment amount. None of our assets were impaired as of December 31, 2017 and 2016.

Goodwill

As of December 31, 2017, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our 2006 gas company acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment.

We applied a qualitative goodwill evaluation model for the annual goodwill impairment test completed in 2017. Based on the results of the qualitative assessment, we believe it was more likely than not that the fair value of the reporting unit exceeded its carrying value as of the testing date, indicating no impairment of our goodwill. The following factors, among others, were considered when assessing whether it was more likely than not that the fair value of the reporting unit exceeded its carrying value for the 2017 test:

- Actual and forecasted financial performance
- Macroeconomic conditions
- Observable industry market multiples

Fuel and Purchased Power

Electric Segment

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. Southwest Power Pool (SPP) Integrated Marketplace (IM) purchased power is also included in fuel and purchased power costs. The net effects of our SPP IM activity, including SPP IM net revenue and net purchased power costs, flow through our fuel recovery mechanisms in each state.

In our Missouri jurisdiction, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for our fuel adjustment clause (FAC). The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from our Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations.

Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and FERC jurisdictions.

At December 31, 2017 and 2016, our Missouri, Kansas and Oklahoma fuel and purchased power costs were in a net under-recovered position by $12.6 million and net over-recovered position by $5.8 million, respectively, which are reflected in our regulatory assets and liabilities.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits (RECs), which are considered inventory, and recorded at zero cost (See Note 11). Revenue from the sale of RECs reduces fuel and purchased power expense.

We have a Stipulation and Agreement with the MPSC granting us authority to manage our emissions allowance inventory in accordance with our Plan for Purchasing and Selling Emissions Allowances (PPSEMA). The PPSEMA allows us to purchase allowances needed for compliance, exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell allowances outright for monetary value. For compliance years 2017 and 2016 we did not exchange or sell any allowances. We classify our allowances as inventory and they are recorded at cost, with allocated allowances being recorded at zero cost. The allowances are removed from inventory on a FIFO basis, and used allowances are considered to be a part of fuel expense (See Note 11). We had the following emissions allowances in inventory at December 31, 2017 and 2016:

Emission Allowances in Inventory	**2017**	**2016**
Acid Rain SO2	32,890	22,118
CSAPR SO2	10,891	11,885
CSAPR NOx (annual)	1,538	946
CSAPR NOx (seasonal)	89	259

Gas Segment

Fuel expense for our gas segment is recognized when the natural gas is delivered to our customers, based on the current cost recovery allowed in rates. A Purchased Gas Adjustment (PGA) clause allows EDG to recover from our customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with the Company's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC. Elements considered part of the PGA factor include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability. The balance is amortized as amounts are reflected in customer billings.

Derivatives

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business. We also acquire Transmission Congestion Rights (TCRs) in an attempt to mitigate congestion costs associated with the power we purchase from the SPP IM (See Note 13).

Electric Segment

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the consolidated balance sheets at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). We record the mark-to-market gains or losses on derivatives used to hedge our fuel and congestion costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered to be normal purchase normal sales (NPNS) transactions. If these transactions do not qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

Gas Segment

Financial hedges for our natural gas business are recorded at fair value on our consolidated balance sheets. Because we have a commission approved natural gas cost recovery mechanism (PGA), we record the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that we will be recovering our costs after the annual true-up period (subject to a prudency review by the MPSC).

Cash flows from hedges for both the electric and gas segments are classified within cash flows from operations.

Pension and Other Postemployment Benefits

We recognize expense related to pension and other postemployment benefits (OPEB) as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postemployment benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. The MPSC has allowed us to adopt this pension cost recovery methodology for EDG as well.

Other Postemployment Benefits (OPEB)

We have regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postemployment plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postemployment plan (other than a multiemployer plan) as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through the comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet, with limited exceptions. Pension and other postemployment employee benefits tracking mechanisms are utilized to allow for future rate recovery of these obligations. We record these as regulatory assets on the consolidated balance sheets rather than as reductions of equity through comprehensive income (See Note 7).

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

Liability Insurance

We are primarily self-insured for workers' compensation claims, general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self-insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for workers' compensation and public liability claims for our electric segment. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Our gas segment is covered by the same excess liability insurance for public liability claims, and workers' compensation claims are covered by a guaranteed cost policy (See Note 11).

Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2017 and 2016, the balance of other noncurrent liabilities is primarily comprised of accruals for self-insurance, customer advances for construction and asset retirement obligations.

Cash & Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $24.1 million and $9.2 million at December 31, 2017 and 2016, respectively.

Restricted Cash

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating costs. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts restricted, which were $1.8 million at December 31, 2017 and 2016, may increase or decrease based on an annual review.

We are required to post cash collateral with the SPP to participate in TCR auctions. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $2.5 million at December 31, 2017 and 2016.

Due to our Plum Point energy station interconnection with Midcontinent Independent System Operator (MISO), we participate in Financial Transmission Rights (FTR) auctions which require us to post cash collateral. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $0.5 million at December 31, 2017 and 2016.

Fuel, Materials and Supplies

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

	2017		2016	
Electric fuel inventory	$	24,116	$	22,944
Natural gas inventory		3,274		2,513
Materials and supplies		32,772		30,590
TOTAL	**$**	**60,162**	**$**	**56,047**

Income Taxes

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes. The temporary differences are measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred as a noncurrent liability and are being amortized over the useful lives of the properties to which they relate. The longest remaining amortization period for investment tax credits is approximately 43 years. Deferred income taxes were recorded on the temporary difference represented by the deferred investment tax credits and a corresponding regulatory liability. This recognizes the expected reduction in rates for future lower income taxes associated with the amortization of the investment tax credits.

Accounting for Uncertainty in Income Taxes

The FASB has issued guidance on accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2011. At December 31, 2017 and 2016, our consolidated balance sheets did not include provisions for any uncertain tax positions. We do not expect any material changes to this tax position within the next twelve months. Our policy is to recognize interest and penalties, if any, related to unrecognized tax benefits in other expenses.

Stock-Based Compensation

Prior to the closing of the Merger, we maintained several stock-based compensation plans, which are described in more detail in Note 8. In accordance with the ASC guidance on stock-based compensation, we recognized compensation expense over the requisite service period of all stock-based compensation awards based upon the fair-value of the award as of the date of issuance.

Recently Issued and Proposed Accounting Standards

Stock Compensation: In March 2016, the FASB issued revised guidance on stock compensation. The updated guidance is intended to simplify some aspects of the accounting for stock compensation such as the income tax impact, classification of awards as either equity or liabilities, and cash flow classification. This guidance is effective for periods beginning after December 15, 2016. The adoption of this update in the first quarter 2017 had no material impact on our consolidated financial statements.

Revenue from Contracts with Customers: In June 2014, the FASB issued new guidance governing revenue recognition. Under the new guidance, an entity is required to recognize revenue in a pattern that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard is effective for interim and annual reporting periods beginning after December 15, 2017. Significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers will be required. This new revenue standard is applicable for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt.

The Company has completed its impact assessment and does not expect significant changes to the pattern of revenue recognition. We intend to adopt the new revenue recognition standard using the modified retrospective method. The only change in the timing of revenue recognition is attributable to our other business unit which will require an increase of $2.5 million in the opening balance of retained earnings. Prior periods will not be retrospectively adjusted. We do not expect the application of the guidance to have a material impact on our results of operations, financial position or liquidity.

Leases: In February 2016, the FASB issued new guidance on accounting for leases. Under the new guidance a lessee will be required to recognize the assets and liabilities arising from leases on the consolidated balance sheets. The new guidance also addresses the income statement treatment for leases. Under the new guidance, leases will be classified as either operating or financing based on criteria that are similar to the old guidance. Lease expenses will be recognized on a straight line basis for operating leases while expenses for capital leases will be similar to the finance pattern utilized today. The new guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. We are currently in the process of creating an inventory of our lease contracts and analyzing the terms and conditions under the requirements of this standard.

Recognition and Measurement of Financial Assets and Financial Liabilities: In January 2016, the FASB issued revised guidance addressing the recognition, measurement, presentation and disclosure of financial instruments. Under the revised guidance, all equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are to be measured at fair value with the changes in fair value recognized in net income. The amended guidance also addresses the impairment assessment of some equity investments, as well as disclosure requirements. The revised guidance is effective for interim and annual periods beginning after December 15, 2017. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

Classification of Certain Cash Receipts and Cash Payments: In August 2016, the FASB issued revised guidance addressing the classification of eight specific cash receipts and cash payments in the statement of cash flows. The revised guidance is intended to reduce diversity in practice in how these items were being classified. The new guidance is effective for interim and annual periods beginning after December 15, 2017. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

Statement of Cash Flows Presentation of Changes in Restricted Cash: In November 2016, the FASB issued revised guidance addressing the presentation of changes in restricted cash on the statement of cash flows intended to address diversity in practice. Under the revised guidance, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The new guidance is effective for interim and annual periods beginning after December 15, 2017. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

Presentation of Net Periodic Benefit Cost: In March 2017, the FASB issued revised guidance addressing the presentation of net periodic benefit cost. The revised guidance requires the service cost component of net benefit cost to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update also only permits the service cost component to be eligible for capitalization when applicable.

Simplifying the test for Goodwilll Impairment: In January 2017, the FASB issued revised guidance intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The revised guidance is effective for fiscal years and interim periods beginning after December 15, 2019.

2. PROPERTY, PLANT AND EQUIPMENT

Our total property, plant and equipment are summarized below for the years ended December 31 (in thousands):

2017	Cost	Accumulated Depreciation & Amortization	Net Book Value
Plant in Service[1,2]			
Generation	$ 1,421,731	$ 370,349	$ 1,051,382
Transmission	375,497	97,727	277,770
Distribution	1,138,375	402,558	735,817
Construction Work in Progress			
Generation	9,292	-	9,292
Transmission	12,230	-	12,230
Distribution	11,189	-	11,189
	$ 2,968,314	**$ 870,634**	**$ 2,097,680**

2016	Cost	Accumulated Depreciation & Amortization	Net Book Value
Plant in Service[1,2]			
Generation	$ 1,415,759	$ 345,814	$ 1,069,945
Transmission	353,885	93,453	260,432
Distribution	1,088,871	384,020	704,851
Construction Work in Progress			
Generation	10,496	-	10,496
Transmission	5,672	-	5,672
Distribution	12,855	-	12,855
	$ 2,887,538	**$ 823,287**	**$ 2,064,251**

(1) Includes intangible property with a cost of $42.3 million and $41.6 million as of December 31, 2017 and 2016, respectively, primarily related to capitalized software and investments in facility upgrades operated by other utilities. Accumulated amortization related to this property in 2017 and 2016 was $19.7 million and $17.6 million, respectively.

(2) Each group includes an allocated portion of Electric General plant primarily consisting of land, structures and equipment used to support utility operations.

The table below summarizes the total provision for depreciation and the depreciation rates for continuing operations, both capitalized and expensed, for the years ended December 31 (in thousands):

Provision for Depreciation[3]	2017	2016[4]
Generation[4]	$ 38,057	$ 38,836
Transmission	8,055	8,084
Distribution	38,089	38,279
Total Annual Provision for Depreciation	84,201	85,199
Amortization	3,527	3,122
Total Annual Depreciation and Amortization	**$ 87,728**	**$ 88,321**

(3) A portion of this amount is reclassified to a regulatory liability for the estimated future cost of removal. See the depreciation discussion under Note 1 and Note 3 for more details.

(4) Includes a one-time recording of $2.6 million as the result of a regulatory agreement.

Annual Depreciation Rates	2017	2016
Generation	2.8%	3.1%
Transmission	2.3%	2.4%
Distribution	3.5%	3.7%
Total Company	**3.0%**	**3.2%**

3. REGULATORY MATTERS

Regulatory Assets and Liabilities and Other Deferred Credits

Changes

There were no changes to regulatory assets and liabilities with regard to their rate base inclusion or amortizable lives from December 31, 2016 to December 31, 2017. In our Missouri rate case, effective September 14, 2016, the activity from TCRs was removed from the fuel adjustment clause; therefore, the portion of unrealized gain or loss on TCR derivatives allocable to Missouri is no longer included in regulatory assets or liabilities. This is now being expensed monthly in the mark-to-market analysis. The regulatory treatment is still allowed through the fuel adjustments mechanisms of Kansas, Oklahoma and Arkansas.

The following table sets forth the components of our regulatory assets and regulatory liabilities on our consolidated balance sheets (in thousands).

	December 31, 2017	December 31, 2016
Regulatory Assets:		
Current:		
Under recovered fuel costs	$ 6,231	$ 847
Current portion of long-term regulatory assets	13,108	7,543
Regulatory assets, current	19,339	8,390
Long-term:		
Pension and other postemployment benefits	88,643	103,186
Income taxes	32,084	48,925
Deferred construction accounting costs(1)	14,344	14,625
Unamortized loss on reacquired debt	8,384	9,058
Under recovered fuel costs	8,419	3,514
Unsettled derivative losses – electric segment	2,133	2,155
System reliability – vegetation management	1,619	2,055
Storm costs(2)	2,448	2,983
Deferred operating and maintenance expense	5,053	1,897
Asset retirement obligation	16,080	11,349
Customer programs	6,052	6,566
Missouri solar initiative(3)	12,337	11,160
Current portion of long-term regulatory assets	(13,108)	(7,543)
Other	1,630	2,155
Regulatory assets, long-term	186,118	212,085
Total Regulatory Assets	**$ 205,457**	**$ 220,475**
Regulatory Liabilities		
Current:		
Over recovered fuel costs	$ 1,427	$ 11,360
Current portion of long-term regulatory liabilities	3,064	3,146
Regulatory liabilities, current	4,491	14,506
Long-term:		
Costs of removal(4)	99,007	98,225
SWPA payment for Ozark Beach lost generation	9,398	11,674
Income taxes(5)	204,076	11,040
Deferred construction accounting costs – fuel(6)	7,418	7,535
Unamortized gain on interest rate derivative	2,691	2,861
Pension and other postemployment benefits	5,131	2,018
Over recovered fuel costs	155	5,817
Current portion of long-term regulatory liabilities	(3,064)	(3,146)
Regulatory liabilities, long-term	324,812	136,024
Total Regulatory Liabilities	**$ 329,303**	**$ 150,530**

(1) Reflects deferrals resulting from the 2005 regulatory plan relating to Iatan 1, Iatan 2 and Plum Point. These amounts are being recovered over the life of the plants.

(2) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado including an accrued carrying charge and deferred depreciation totaling $2.1 million at December 31, 2017.
(3) Resulting from the Missouri Clean Energy Initiative and consists of approximately 1,255 solar rebate applications processed as of December 31, 2017, (compared to 912 as of December 31, 2016), resulting in solar rebate-related costs totaling approximately $13.0 million.
(4) As part of our depreciation rates, we accrue the estimated cost of dismantling and removing plant from service upon retirement and these costs are reflected here. See the depreciation discussion under Note 1 and Note 2 for more detail.
(5) The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $143,428.
(6) Resulting from the regulatory plan requiring deferral of the fuel and purchased power impacts of Iatan 2.

Unamortized losses on debt and losses on interest rate derivatives are not included in rate base, but are included in our capital structure for rate base purposes. The remainder of our regulatory assets are not included in rate base, generally because they are not cash items. However, as of December 31, 2017, the costs of all of our regulatory assets are currently being recovered except for approximately $82.6 million of pension and other postemployment costs primarily related to the unfunded liabilities for future pension and OPEB costs. We expect recovery of the unfunded amount but the timing of the recovery will be based on the changing funded status of the pension and OPEB plans in future periods.

The regulatory income tax assets and liabilities are generally amortized over the average depreciable life of the related assets. The loss on reacquired debt and the loss and gain on interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 0.5 to 27 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Pension and OPEB tracking mechanisms are recovered over a five-year period. The cost of removal regulatory liability is amortized as removal costs are incurred.

RATE MATTERS

We routinely assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric, natural gas services and water (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of the utility plant or write-off as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate-making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2016:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri – Electric	October 16, 2015	$ 20,390,000	4.46%	September 14, 2016
Oklahoma – Electric	December 21, 2016	$ 992,170	11.76%	August 31, 2017
Kansas – Electric	January 6, 2017	$ 958,186	4.83%	July 1, 2017
Arkansas – Electric	July 21, 2016	$ 642,976	3.70%	November 1, 2016

Electric Segment

Missouri

2015 Rate Case: On October 16, 2015, we filed a request with the Missouri Public Service Commission (MPSC) for changes in rates for our Missouri electric customers, seeking an annual increase in total revenue of approximately $33.4 million, or approximately 7.3%. On June 21, 2016, we announced we had filed a Unanimous Stipulation and

Agreement (“the Agreement”) with the MPSC. The MPSC issued an order approving the Agreement on August 10, 2016 with rates effective September 14, 2016. The Agreement allows an annual increase in base revenues of approximately $20.4 million, or 4.46%. Base revenues established by the Agreement are lower than the originally requested level of $33.4 million due primarily to lower fuel and purchased power costs than those built into current customer rates. The offsetting effect of reduced revenues and reduced fuel costs results in little impact to gross margin. The most significant factor driving the rate request was the cost associated with the conversion of the Riverton Unit 12 natural gas combustion turbine to combined cycle operation. The Agreement calls for the Fuel Adjustment Charge to remain in effect. In addition, a tracking mechanism for non-labor operating and maintenance expenses for the Riverton 12 Combined Cycle Unit will continue and tracking of pension and other postemployment benefit expenses will continue.

Integrated Resource Plan and Missouri Energy Efficiency Investment Act

We filed our most recent Integrated Resource Plan (IRP) with the MPSC on April 1, 2016. The IRP analysis of future loads and resources is normally conducted once every three years. This IRP reflects the completion of our 2013 Compliance Plan discussed in Note 11.

On August 24, 2016, an Amended Stipulation and Agreement as to Division of Energy and Renew Missouri was filed in the Merger case in which we agreed to make a Missouri Energy Efficiency Investment Act (MEEIA) filing, provided a statewide Technical Reference Manual (TRM) has been approved by the state, and provided our next Triennial IRP (2019 or 2022, depending on the date a TRM is approved) favors a plan with increased demand-side management (DSM) investments. We will work with the Missouri Division of Energy (DE), the MPSC Staff, the Office of the Public Counsel (OPC) and other parties through the existing DSM Advisory Group to review and consider the viability of adopting additional energy efficiency programs for our customers. Within one year of the MPSC’s finding of substantial compliance of the Empire IRP that follows MPSC approval of a TRM, we will develop and submit an application for approval of a portfolio of DSM programs under MEEIA, so long as any such portfolio is a part of our adopted preferred resource plan in our IRP, or has been analyzed through the integration process required and the portfolio and any DSM submitted in the application is fully compliant with the MEEIA statute and applicable regulations.

Kansas

2016 Rate Case: On September 16, 2016, we filed a request with the Kansas Corporation Commission (KCC) for changes in rates for our Kansas electric customers, seeking an annual increase in total revenue of approximately $6.4 million, or approximately 25.7%. On October 6, 2016, we announced the filing with the KCC of a Unanimous Settlement Agreement with respect to the joint application for approval of the Merger filed March 16, 2016, subject to approval by the KCC. As a condition of the Unanimous Settlement Agreement that was reached with the KCC staff, and approved by the KCC, our pending Kansas rate case was withdrawn and current base rates would remain in effect through at least January 1, 2019. The agreement also provided that we would file a request to update the current Environmental Recovery Rider in Kansas to include costs associated with the Riverton 12 Combined Cycle project, which would produce approximately $1.0 million of additional revenue annually.

On January 11, 2017, we filed a request to implement a rider, the Asbury Environmental and Riverton Rider (AERR), in place of the Asbury Environmental Rider (AER) currently in effect in our Kansas jurisdiction. The new rider will provide a mechanism to begin recovering costs related to the $168 million combined cycle generating unit at the Riverton Power Plant. This rider was approved by the KCC with an effective date of July 1, 2017, resulting in an incremental revenue of approximately $958,186 annually.

2017 Ad Valorem Tax Surcharge

On January 22, 2015, we filed an Application with the KCC requesting approval of our Ad Valorem Tax Surcharge (AVTS). The original request sought approval for an annual increase of $0.3 million related to increases in Ad Valorem taxes which exceed amounts currently included in base rates. The original request provided for an annual true-up calculation of the surcharge. On February 19, 2015, the KCC approved the request. The new rate was effective February 23, 2015. On January 30, 2017, we filed our annual true-up calculation with the KCC requesting approval for a revision to the AVTS. The request sought approval for an annual increase of an additional $0.6 million related to increases in Ad Valorem taxes which exceed amounts currently included in our AVTS rider. On February 28, 2017, the KCC approved the request. The new rate was effective March 1, 2017.

Oklahoma

On June 8, 2015, the Governor of Oklahoma approved an administrative ruling that provides customer rate reciprocity to electric companies who serve less than 10% of total customers within the state of Oklahoma. As a result, future increases in Missouri customer rates approved by the MPSC could be effective for our Oklahoma customers, subject to Oklahoma Corporation Commission (OCC) approval. On October 26, 2015, we filed a request with the OCC to adopt the Missouri customer electric rates requested in our October 16, 2015 Missouri rate filing, discussed above, for our Oklahoma customers.

On September 23, 2016, we filed with the OCC for a change in rates for Oklahoma customers pursuant to the rate reciprocity rule mentioned above, seeking an annual increase in base revenues of approximately $4.7 million, or approximately 37.8% for Oklahoma electric customers. The OCC issued an order on October 13, 2016 rejecting the Missouri rates filed under the reciprocity rule. On November 2, 2016, we filed an application requesting that the current case be dismissed and filed a notice of intent to file an application seeking to implement a plan which would modify the rates and charges for our Oklahoma jurisdiction customers.

On December 21, 2016, we filed a request with the OCC for changes in rates for our Oklahoma electric customers, seeking an increase in annual revenues of approximately $3.8 million, or approximately 27.58%. Primary drivers for this case include the $112 million Air Quality Control System (AQCS) at the Asbury Power Plant, the $168 million combined cycle generating unit at the Riverton Power Plant; upgrades to financial, asset, and work management software systems; and other reliability and system improvements to serve customers. On August 17, 2017, the OCC issued an Order authorizing an ECP Capital Investment Rider which serves to capture the environmental costs of the Asbury and Riverton 12 projects. This rider became effective on August 31, 2017 and is estimated to increase revenues annually approximately $1.0 million.

Arkansas

2016 Cost Recovery Rider

On July 21, 2016, we filed a request with the Arkansas Public Service Commission (APSC) to implement a cost recovery rider for the conversion of the existing Riverton Unit 12 to combined cycle operation. The rider request was approved on October 25, 2016 and we began collecting approximately $0.6 million of additional annual revenue on November 1, 2016.

Customer Savings Plan

On October 31, 2017, The Empire District Electric Company filed with the MPSC, KCC, OCC, and the APSC an application requesting approval of a Customer Savings Plan that proposes to save customers $325 million over the next 20 years. The “Customer Savings Plan” is generally comprised of the acquisition or construction of up to 800-megawatts of wind generation facilities and the retirement of a coal generation facility and the associated establishment of a regulatory asset.

FERC

We have in place a cost-based transmission formula rate (TFR). On June 13, 2013, we, the KCC and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (“the Agreement”) with the FERC. The Agreement included a TFR that would establish a return on equity (ROE) of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC conditionally approved the Agreement on November 18, 2013, and we made a compliance filing with FERC on December 18, 2013 in connection with this conditional approval. The FERC approved our compliance filing on June 12, 2014.

We have in place a cost-based generation formula rate (GFR). Our GFR requires an update to be completed annually for rates effective June 1. On October 29, 2014, Empire made a “limited” Section 205 filing to request some minor changes in the existing GFR formula to incorporate the impact of the recent implementation of the SPP IM. As a result of this filing, our customers' share of the margins we receive from sales into the IM will be passed on to them through the monthly fuel and purchased power cost adjustment mechanism rather than making one-time adjustments at each annual update. This filing was approved by FERC on January 13, 2015.

MARKETS AND TRANSMISSION

Electric Segment

Day Ahead Market: As part of the IM, Empire and other SPP market participants submit generation offers and demand bids for the sale and purchase of power into the SPP market. The SPP serves as a centralized commitment and dispatch of SPP members' generation resources while balancing economics and reliability. The SPP reports that approximately 95% of all next day generation needed throughout the SPP territory is being cleared through the IM. When we sell more generation to the market than we purchase for a given settlement period, the net sale is included as part of electric revenues. When we purchase more generation from the market than we sell, the net purchase is recorded as a component of fuel and purchased power on our consolidated financial statements. The net financial effect of these IM transactions is included in our fuel adjustment mechanisms and therefore has little impact on gross margin. We also acquire TCRs through annual and monthly processes in an attempt to mitigate congestion costs associated with the power we purchase from the IM. These rights are recorded as reductions to purchased power costs.

FERC Order No. 1000: In July 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities) which requires all public utility transmission providers to allow transmission developers outside their retail distribution service territory to participate in regional transmission planning. Order No. 1000 eliminates the federal right of first refusal for entities that develop transmission projects within their own retail distribution service territories to construct transmission facilities selected in a regional transmission plan. This order will directly affect our rights to build 161kV and above transmission facilities within our retail service territory.

Order No. 1000 also directed transmission providers to develop policy and procedures for regional and interregional transmission planning as well as regional and interregional transmission cost allocation for approved transmission projects. We continue to participate in the SPP processes to understand the impact of these FERC orders on our ability to construct new facilities within our service territory as well as their influence on promoting construction of transmission projects on or near our borders with our neighbors. SPP completed and filed with the FERC a required interregional policy and procedure compliance filing, and while FERC partially approved SPP's compliance filing, remaining issues have been addressed in a subsequent filing that is currently waiting FERC approval.

SPP/Midcontinent Independent System Operator (MISO) Joint Operating Agreement and Plum Point Delivery: Due to Plum Point's physical location and interconnection, transmission service from Entergy/MISO is required for delivery. On December 19, 2013, Entergy voluntarily integrated its generation, transmission, and load into the MISO regional transmission organization. Based on the current terms and conditions of MISO membership, Entergy's participation in MISO has increased transmission delivery costs for our Plum Point power station as well as utilized our transmission system without compensation.

As a result, we have participated with the SPP members and other impacted utilities in two separate FERC settlement proceedings in an effort to reduce the costs to our customers. On October 13, 2015, SPP members, SPP, MISO and MISO members filed a settlement at the FERC regarding MISO's unreserved and uncompensated use of the SPP members' systems. As approved by the FERC, the agreement provides compensation and governance for the continued shared use of the transmission system among MISO, SPP and other impacted utilities. The regional through and out transmission delivery rate (RTOR) dispute regarding Plum Point also proceeded through settlement discussions and a resulting settlement agreement was filed with the FERC on February 25, 2016. The settlement closed on June 23, 2016 and we withdrew all claims on July 6, 2016. We received a total of $2.1 million in MISO Through-and Out refunds in 2016 with rate reductions continuing through 2023-2025.

Gas Segment

Non-residential gas customers whose annual usage exceeds certain amounts may purchase natural gas from a source other than EDG. EDG does not have a non-regulated energy marketing service that sells natural gas in competition with outside sources. EDG continues to receive non-gas related revenues for distribution and other services if natural gas is purchased from another source by our eligible customers.

Other - Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $0.7 million of expense related to rate cases under other noncurrent assets and deferred charges. These amounts will be amortized over varying periods based upon the completion of the specific cases. Based on past history, we expect all these expenses to be recovered in rates.

4. STOCKHOLDER'S EQUITY

Employee Benefit Plans

Prior to the closing of the Merger, Empire's Employee Stock Purchase Plan (ESPP) permitted the granting to eligible employees of options to purchase our common stock at a discounted price. As of December 31, 2016 there were 707,737 shares available for issuance in this plan. Under our Employee 401(k) Plan and ESOP, we matched a percentage of each employee's deferrals by contributing shares of our common stock. At December 31, 2016, there were 78,453 shares available to be issued. (See Note 7 for further discussion of these plans). Pursuant to the Merger, Empire employees are now participants in the APUC Employee Share Purchase Plan which allows eligible employees to use a portion of their earnings to purchase common shares of APUC.

Equity Based Compensation

Prior to the closing of the Merger, we maintained several stock-based awards programs, which are described in Note 8. Our 2015 Stock Incentive Plan provided for grants of up to 500,000 shares of common stock which were cancelled as a result of the Merger. At December 31, 2016, there were 459,093 shares available to be issued.

Dividends

Beginning in 2017, the Board of Directors declares dividends, if any, to be paid to the parent company. The dividends paid in 2017 were $32.0 million.

On December 22, 2016, The Empire District Electric Company Board of Directors declared a special prorated dividend in the amount of $0.002857 per share, per day on the Company's outstanding common stock that accrued from December 1, 2016 until December 31, 2017, the day immediately preceding the Merger Closing Date. The special prorated dividend was equal to the daily equivalent of the then-current quarterly dividend rate of $0.26 per share, payable to stockholders of record on December 30, 2016. The special prorated dividend totaling approximately $3.9 million was accrued at December 31, 2016 and was paid on January 17, 2017.

The EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million. The EDE Mortgage permits the payment of any dividend or distribution on, or purchase of, shares of our common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

5. LONG-TERM DEBT

At December 31, 2017 and 2016, the balance of long-term debt outstanding was as follows (in thousands):

	2017	2016
First mortgage bonds (EDE):		
6.375% Series due 2018 [(1)]	$ 90,000	$ 90,000
4.65% Series due 2020 [(1)]	100,000	100,000
3.58% Series due 2027 [(1)]	88,000	88,000
3.59% Series due 2030 [(1)]	60,000	60,000
3.73% Series due 2033 [(1)]	30,000	30,000
5.875% Series due 2037 [(1)]	80,000	80,000
5.20% Series due 2040 [(1)]	50,000	50,000
4.32% Series due 2043 [(1)]	120,000	120,000
4.27% Series due 2044 [(1)]	60,000	60,000
First mortgage bonds (EDG):		
6.82% Series due 2036 [(1)]	55,000	55,000
	733,000	733,000
Senior Notes, 6.70% Series due 2033 [(1)]	62,000	62,000
Senior Notes, 5.80% Series due 2035 [(1)]	40,000	40,000
Capital lease obligations	3,208	3,579
Less unamortized debt expense	(7,316)	(7,954)
Less unamortized net discount	(529)	(581)
	830,363	830,044
Current unamortized debt expense	-	-
Less current obligations of long-term debt	-	-
Less current obligations under capital lease	(369)	(329)
TOTAL LONG-TERM DEBT	**$ 829,994**	**$ 829,715**

(1) We may redeem some or all of the notes at any time at 100% of their principal amount, plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

EDE Mortgage Indenture

Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The principal amount of all series of first mortgage bonds outstanding at any one time under the Indenture of Mortgage and Deed of Trust of The Empire District Electric Company (EDE Mortgage) is limited by terms of the mortgage to $1.0 billion. Based on the $1.0 billion limit, and our current level of outstanding first mortgage bonds, we are limited to the issuance of $328.9 million of new first mortgage bonds. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. The annual interest coverage requirement and retired bonds or 60% of net property additions test would permit the issuance of more than $328.9 million of first mortgage bonds; however, as discussed above, we are otherwise limited to the issuance of no more than $328.9 million of new first mortgage bonds. As of December 31, 2017, we are in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the Indenture of Mortgage and Deed of Trust of The Empire District Gas Company (EDG Mortgage) is limited by terms of the mortgage to $300.0 million. Substantially all of the property, plant and equipment of The EDG is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of December 31, 2017, EDG is unable to issue any additional first mortgage bonds as its coverage ratio is 1.67 to 1.0. As of December 31, 2017, we are in compliance with all restrictive covenants of the EDG Mortgage.

Our long-term debt obligations over the next five years are as follows (in thousands):

	Payments Due By Period		
Long-Term Debt Payout Schedule (Excluding Unamortized Discount) (in thousands)	**Total**	**Regulated Entity Debt Obligations**	**Capital Lease Obligations**
2018	$ 90,344	$ 90,000	$ 344
2019	366	-	366
2020	100,387	100,000	387
2021	413	-	413
2022	441	-	441
Thereafter	646,257	645,000	1,257
Total long-term debt obligations	**838,208**	**$835,000**	**$ 3,208**
Less current obligations and unamortized discount	8,214		
TOTAL LONG-TERM DEBT	**$829,994**		

6. SHORT-TERM BORROWINGS

At December 31, 2017, total short-term borrowings consisted of $5.6 million in commercial paper and no borrowings under our line of credit. During 2017 and 2016 our short-term borrowings outstanding averaged (in millions):

	2017	**2016**
Average borrowings outstanding	$10.1	$14.3
Highest month end balance	$40.3	$36.0

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2017 and 2016 were:

	2017	**2016**
Weighted average interest rate	1.14%	0.84%
Weighted average interest rate of borrowings outstanding	1.85%	1.02%

Effective February 23, 2018, our $200 million 5-year Credit Agreement, which was set to expire in October 2019, was terminated. Empire will maintain its commercial paper program but its program will be supported by a credit facility maintained by its parent company, Liberty Utilities Co. Also effective February 23, 2018, Liberty Utilities Co. entered into a new 5-year $500 million credit facility which is available to Liberty for, among other things, working capital and general corporate purposes, including supporting the working capital needs of its subsidiaries.

The former credit facility required our total indebtedness to be less than 65.0% of our total capitalization at the end of each fiscal quarter and a failure to maintain this ratio would result in an event of default under the credit facility and would have prohibited us from borrowing funds thereunder. As of December 31, 2017, we were in compliance with this covenant as our total indebtedness to total capitalization was 50.3%. The credit facility was also subject to cross-default if we default on more than $25 million in the aggregate on our other indebtedness. As of December 31, 2017, we were not in default under any of our debt obligations.

The former credit agreement did not legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under the agreement at December 31, 2017; however, $5.6 million was used to back up our outstanding commercial paper.

7. RETIREMENT AND OTHER EMPLOYEE BENEFITS

We record retirement benefits in accordance with the ASC guidance on accounting for pension and other postemployment benefits, and have recorded the appropriate liabilities to reflect the unfunded status of our benefit plans, with offsetting entries to a regulatory asset, because we believe it is probable the unfunded amount of these plans will be afforded rate recovery. Additionally, the MPSC agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. These amounts, which are recorded as regulatory assets, are being amortized. The tax effects of these entries are reflected as deferred tax assets and liabilities and regulatory liabilities.

Annually, we evaluate the discount rate, retirement age, compensation rate increases, expected return on plan assets, healthcare cost trend rate, and other actuarial assumptions related to the pension benefit and post-retirement medical plan. When selecting the discount rate we utilize a modeling process that involves selecting a portfolio of above median, AA or better, bonds whose cash flows match the timing and extent of the expected cash flows of the Empire pension plan. In evaluating these assumptions, many factors are considered, including, current market conditions, asset allocations, changes in demographics and the views of leading financial advisors and economists. In evaluating the expected retirement age assumption, we consider the retirement ages of past employees eligible for pension and medical benefits together with expectations of future retirement ages. It is reasonably possible that changes in these assumptions will occur in the near term and, due to the uncertainties inherent in setting assumptions, the effect of such changes could be material to the Company’s consolidated financial statements. A roll forward technique is used to value the year ending pension obligations. The roll forward technique values the year-end obligation by rolling forward the beginning-of-year obligation using the demographic assumptions disclosed below. The economic assumptions are updated as of the end of the year. All of the benefit plans have been measured as of December 31, 2017, consistent with previous years. See Note 1.

Pensions

Our noncontributory defined benefit pension plan includes all employees meeting minimum age and service requirements. Employees hired on or after January 1, 2014 accrue benefits based on a cash balance methodology. Employees hired prior to January 1, 2014 were given a one-time option to convert to the cash balance methodology, or remain with our traditional average annual basic earnings formula, by December 31, 2014. Both benefit formulas allow for a lump-sum distribution of vested benefits. Lump-sum distributions totaled approximately $25.4 million and $14.7 million during 2017 and 2016, respectively. In 2017, lump-sum distributions required settlement accounting according to ASC 715, and resulted in a settlement gain of approximately $0.5 million.

Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the plan, as required by the MPSC.

Our net pension liability decreased $14.2 million in 2017, which was recorded as a decrease in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The decrease in the liability is due to positive investment returns for the year and benefit payments offsetting the other components of the projected benefit obligation. Our contribution is estimated to be approximately $7.5 million for 2018. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2019, the performance of our pension assets during 2018.

We also have a supplemental retirement program (“SERP”) for designated former officers of the Company, which we fund from Company funds as the benefits are paid. The liability for this plan increased $3.8 million in 2017. Subsequent to the closing of the Merger, the SERP plan was frozen. See Note 15 for further discussion of the Merger Agreement.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2018	$17.7	$0.5
2019	17.0	0.5
2020	17.3	0.6
2021	18.8	1.0
2022	18.7	1.0
2023-2027	92.4	4.4

Other Postemployment Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 will be offered unsubsidized retiree healthcare benefits upon retirement.

Our net liability decreased $2.8 million in 2017, which was recorded as a decrease in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The decrease in the liability is primarily due to positive investment returns. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postemployment benefits. We expect to be required to fund approximately $0.5 million in 2018.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust
2018	$3.0
2019	3.4
2020	3.7
2021	3.9
2022	4.2
2023-2027	25.6

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:	Pension		SERP		OPEB	
	2017	2016	2017	2016	2017	2016
Benefit obligation at beginning of year	$ 245,146	$ 243,690	$ 11,340	$ 9,886	$ 97,761	$ 101,467
Service cost	7,767	7,533	-	176	2,668	3,271
Interest cost	9,836	10,581	555	434	4,166	4,668
Amendments	-	-	-	-	-	-
Net actuarial (gain)/loss	14,449	8,401	3,617	1,216	7,773	(8,804)
Plan participant's contribution	-	-	-	-	1,251	1,204
Benefits and expenses paid	(33,944)	(25,059)	(421)	(372)	(3,678)	(4,155)
Federal subsidy	-	-	-	-	134	110
Benefit obligation at end of year	**$243,254**	**$245,146**	**$ 15,091**	**$ 11,340**	**$ 110,075**	**$ 97,761**

Reconciliation of Fair Value of Plan Assets:	**Pension**		**SERP**		**OPEB**	
	2017	**2016**	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets at beginning of year	$ 184,509	$ 186,845	$ -	$ -	$ 91,532	$ 85,369
Actual return on plan assets – gain/(loss)	32,068	10,205	-	-	16,677	6,318
Employer contribution	14,200	12,518	421	372	784	2,611
Benefits paid	(33,944)	(25,059)	(421)	(372)	(3,678)	(4,015)
Plan participant's contribution	-	-	-	-	1,251	1,143
Federal subsidy	-	-	-	-	134	106
Fair value of plan assets at end of year	**$ 196,833**	**$ 184,509**	**$ -**	**$ -**	**$ 106,700**	**$ 91,532**

	Pension		**SERP**		**OPEB**	
Reconciliation of Funded Status:	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Fair value of plan assets	$196,833	$184,509	$ -	$ -	$ 106,700	$ 91,532
Projected benefit obligations	(243,254)	(245,146)	(15,091)	(11,340)	(110,075)	(97,761)
Funded status	**$(46,421)**	**$(60,637)**	**$(15,091)**	**$(11,340)**	**$ (3,375)**	**$ (6,229)**

The employee pension plan accumulated benefit obligation at December 31, 2017 and 2016 is presented in the following table (in thousands):

	Pension Benefits		**SERP**	
	2017	**2016**	**2017**	**2016**
Accumulated benefit obligation	$220,362	$223,741	$ 15,091	$ 10,455

Amounts recognized in the balance sheet consist of (in thousands):

	Pension		**SERP**		**OPEB**	
	2017	**2016**	**2017**	**2016**	**2017**	**2016**
Other deferred charges	$ -	$ -	$ -	$ -	$ 809	$ 143
Accounts payable and accrued liabilities	$ -	$ -	$ 513	$ 697	$ -	$ 164
Pension and other postemployment benefit obligations	$ 46,421	$ 60,637	$ 14,578	$ 10,643	$ 4,184	$ 6,207

Net periodic benefit pension cost for 2017 and 2016, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset (See Note 3), is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:	**Pension**		**OPEB**		**SERP**	
	2017	**2016**	**2017**	**2016**	**2017**	**2016**
Service cost	$ 7,767	$ 7,533	$ 2,668	$ 3,271	$ -	$ 176
Interest cost	9,836	10,581	4,166	4,668	555	434
Expected return on plan assets	(12,368)	(13,757)	(5,389)	(5,498)	-	-
Amortization of prior service cost/(benefit)(1)	-	(630)	-	(1,011)	-	(14)
Amortization of actuarial loss(1)	-	8,702	-	1,121	-	569
Net periodic benefit cost	**$ 5,235**	**$ 12,429**	**$ 1,445**	**$ 2,551**	**$ 555**	**$ 1,165**

(1)Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the consolidated balance sheets.

The tables below present other changes in plan assets and benefit obligations recognized in the regulatory asset accounts for the year (in thousands):

Regulatory Assets	Beginning Balance 12/31/16	Reclassification due to merger[(1)]	Amount Recognized: Current Year Actuarial (Gain)/Loss	Amount Recognized: Amortization of Actuarial Gain	Amount Recognized: Amortization of Prior Service (Cost)/Credit	Ending Balance 12/31/17
Pension	$ 86,769	(86,769)	(5,250)	496[(2)]		$ 82,015
SERP	$ 6,200	(6,200)	3,618	-		$ 9,818
OPEB	$ 768	(768)	(3,515)	-		$ (2,747)

[(1)]As a result of the Merger, these balances were reclassified to other regulatory assets as we believe they will continue to be recoverable through rates.
[(2)] Amounts represent a gain due to plan settlement.

The following table presents the amount of net actuarial gains/losses, transition obligations / assets and prior period service costs in regulatory assets not yet recognized as a component of net periodic benefit cost. It also shows the amounts expected to be recognized in the subsequent year. The following table presents those items for the employee pension plan and other benefits plan at December 31, 2017, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2017	Subsequent Period	2017	Subsequent Period	2017	Subsequent Period
Net actuarial loss	$ -	$ -	$ -	$ -	$ -	$ -
Prior service cost (benefit)	-	-	-	-	-	-
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

The measurement date used to determine the pension and other postemployment benefits is December 31. The assumptions used to determine the benefit obligation and the periodic costs are as follows:

Weighted-average Assumptions Used to Determine the Benefit Obligation as of December 31:

	Pension Benefits		OPEB	
	2017	2016	2017	2016
Discount rate	3.54%	4.09%	3.63%	4.19%
Rate of compensation increase	3.00%	3.50%	3.00%	3.50%

Weighted-average Assumptions used to Determine the Net Benefit Cost (Income) as of January 1:

	Pension Benefits		OPEB	
	2017	2016	2017	2016
Discount rate	4.09%	4.40%	4.19%	4.48%
Expected return on plan assets	7.00%	7.55%	6.75%	6.36%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%

The expected long-term rate of return assumption was based on historical return and adjusted to estimate the potential range of returns for the current asset allocation. The assumed 2017 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 6.25%. Each trend rate decreases 0.25% through 2023 to an ultimate rate of 4.75% in 2024 and subsequent years.

The healthcare cost trend rate affects projected benefit obligations. A 1% change in assumed healthcare cost growth rates would have the following effects (in thousands):

	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1,638	$ (1,240)
Effect on post-retirement benefit obligation	$ 20,929	$ (16,359)

Fair Value Measurements of Plan Assets

See Note 13 for a discussion of fair value measurements. The Company believes that it is appropriate for the pension fund to assume a moderate degree of investment risk with diversification of fund assets among different classes (or types) of investments, as appropriate, as a means of reducing risk. Although the pension fund can and will tolerate some variability in market value and rates of return in order to achieve a greater long-term rate of return, primary emphasis is placed on preserving the pension fund's principal. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee. The following is a description of the valuation methodologies used for assets measured at fair value using significant other observable, or significant unobservable inputs.

Short-term investments: Valued at cost, which approximates fair value.

Common/Collective trusts: Valued at the fair value based on audited financials of the trusts.

U.S. corporate and foreign issue debt: Valued at quoted market prices when available in an active market. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of securities with similar characteristics, or discounted cash flows.

Equity long/short hedge funds: Valued at the net asset value reported in the annual audited financial statements and updated monthly based on changes in the value of the underlying funds reported by the fund manager.

Plan Assets

We utilize fair value in determining the market-related values for the different classes of our pension plan assets. The market-related value is determined based on smoothing actual asset returns in excess of (or less than) expected return on assets over a 5-year period.

The Company's investment strategy for its pension plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

Asset Allocation

Asset Class	Target (%)	Range (%)
Equity securities	72%	49% - 79%
Debt securities	28%	21% - 51%
Other	-%	-%

Pension Plan Assets

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2017 and December 31, 2016 (in thousands):

	Fair Value Measurements as of December 31, 2017				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Common stock	$ 14,566	$ -	$ -	$ 14,566	7.4%
Mutual funds					
Domestic equity	52,161	-	-	52,161	26.5%
International equity	57,868	-	-	57,868	29.4%
Lifestyle funds	14,369	-	-	14,369	7.3%
Fixed income					
Mutual funds	42,713	-	-	42,713	21.7%
Private placement	-	15,156		15,156	7.7%
	$ 181,677	**$ 15,156**	**$ -**	**$ 196,833**	**100.0%**

	Fair Value Measurements as of December 31, 2016				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$ -	$ 70	$ -	$ 70	0.0%
Equity securities					
Common collective trusts	-	95,087	-	95,087	51.5%
Fixed income					
Common collective trust	-	52,146	-	52,146	28.3%
Other types of investments					
Common collective trust	-	35,372	-	35,372	19.2%
Equity long/short hedge funds	-	-	1,834	1,834	1.0%
	$ -	**$ 182,675**	**$ 1,834**	**$ 184,509**	**100.0%**

Fair Value Measurements Using Significant Unobservable Inputs (Level 3) – December 31,

	2017	2016
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1	$ 1,834	$ 37,970
Actual return on plan assets:		
Relating to assets still held at the reporting date	-	-
Relating to assets sold during the period	-	534
Purchases	-	-
Sales	-	(36,670)
Settlements	(1,834)	-
Transfers into and (out of) Level 3	-	-
Ending Balance, December 31	**$ -**	**$ 1,834**

OPEB plan assets

The following fair value hierarchy table presents information about the OPEB fund assets measured at fair value as of December 31, 2017 and December 31, 2016 (in thousands):

	Fair Value Measurements as of December 31, 2017				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash	$ 829	$ -	$ -	$ 829	0.8%
Mutual funds					
Fixed income	22,291	-	-	22,291	20.9%
Domestic equity	36,196	-	-	36,196	33.9%
International equity	47,384	-	-	47,384	44.4%
	$ 106,700	**$ -**	**$ -**	**$ 106,700**	**100.0%**

	Fair Value Measurements as of December 31, 2016				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Equity securities					
Common collective trusts	$ -	$ 52,300	$ -	$ 52,300	57.1%
Fixed income					
Common collective trusts	-	36,645	-	36,645	40.0%
Other types of investments					
Common collective trusts	-	2,727	-	2,727	3.0%
	$ -	$ 91,672	$ -	91,672	
Payable for securities purchased				(140)	-0.1%
				$ 91,532	**100.0%**

Employee Stock Purchase Plan

Prior to the closing of the Merger, our Employee Stock Purchase Plan (ESPP) permitted the granting to eligible employees options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The expense incurred related to this plan was immaterial. The look-back feature of this plan was valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. Pursuant to the Merger, the ESPP was terminated on January 1, 2017.

	2016
Subscriptions outstanding at December 31	24,700
Maximum subscription price	$ 30.29
Shares of stock issued	56,908
Stock issuance price	$ 21.09

Assumptions for valuation of these shares are shown in the table below.

	2016
Weighted average fair value of grants	$ 6.11
Risk-free interest rate	0.70%
Dividend yield	3.10%
Expected volatility [1]	27.00%
Expected life in months	12
Grant date	6/1/2016

[1] One-year historical volatility

Subsequent to the Merger, all of the unused amounts (24,700 shares) credited to participant accounts through payroll deduction were refunded to participants, together with interest as provided by the Plan.

401(k) Plan and ESOP

Our Employee 401(k) Plan and ESOP (the 401(k) Plan) allows participating employees to defer up to 25% of their annual compensation up to an Internal Revenue Service specified limit. For employees participating in the cash balance formula of the pension plan, discussed above, we match 100% of their deferrals, not to exceed 6% of the employee's eligible compensation. Prior to the closing of the Merger, the first 3% of the matching contribution was made in shares of The Empire District Electric Company common stock with the remaining portion made by contributing cash. Prior to the closing of the Merger, for employees remaining with the traditional average annual basic earnings formula of the pension plan, we matched 50% of their deferrals by contributing shares of The Empire District Electric Company common stock, with such matching contributions not to exceed 3% of the employee's eligible compensation. We record the compensation expense at the time the matching contributions are made to the plan.

Effective November 1, 2016, the 401(k) Plan was amended to allow employer matching contributions to be made in either cash or employer stock. Subsequent to the Merger, as part of the APUC 401(k) Plan, matching employer contributions are made in cash.

	2017	2016
Shares contributed	-	51,163

8. EQUITY COMPENSATION

Prior to the closing of the Merger, we maintained several stock-based awards and programs, which are described below. Performance-based restricted stock awards and time-vested restricted stock were valued as liability awards, in accordance with fair value guidelines. We allowed employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards were classified as liability instruments under the ASC guidance on share-based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable years ended December 31 (in thousands):

	2017	2016
Compensation expense	$ 1,899	$ 6,583
Tax benefit recognized	706	2,457

Stock Incentive Plans

Our 2006 Stock Incentive Plan (the "2006 SIP"), which expired on December 31, 2015, was replaced by the 2015 Stock Incentive Plan (the "2015 SIP"). The 2015 SIP was adopted by stockholders at the annual meeting on May 1, 2014 and provided for grants of up to 500,000 shares of common stock through January 2025. At December 31, 2016, there were 459,093 shares available to be issued. The 2015 SIP permitted grants of stock options and restricted stock to qualified employees and permitted Directors and, if approved by the Compensation Committee of the Board of Directors, qualified employees to receive common stock in lieu of cash. Certain executive officers and other senior managers applied to receive annual incentive awards related to the 2014, 2015 and 2016 performance in the form of Empire common stock rather than cash. These requests were granted by the Compensation Committee of the Board of Directors under the terms of our 2006 and 2015 SIPs. The terms and conditions of any option or stock grant were determined by the Board of Directors' Compensation Committee, within the provisions of these Stock Incentive Plans.

Pursuant to the Merger discussed above, the 2006 SIP and the 2015 SIP were terminated on January 1, 2017. See Note 15.

Time-Vested Restricted Stock Awards

Prior to the Merger, time-vested restricted stock awards that vested after a three-year period were granted to qualified individuals. No dividend rights accumulated during the vesting period. Time-vested restricted stock were valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminated during the vesting period because of death, retirement or disability, the participant was entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, to be distributed following the date of termination, with the remainder of the award forfeited. If employment terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards were forfeited on the date of the termination, unless the Board of Directors' Compensation Committee determined, in its sole discretion, that the participant was entitled to a pro-rata portion of the award. In addition, if a change in control occurred during the vesting period, a pro-rata portion of the time-vested restricted stock awards vested upon such change in control, and any portion of such awards that remained unvested immediately after the change in control was forfeited. Our Merger with Liberty Central triggered a change in control and the resulting distribution is further described below.

The fair value measurements for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31	
	2017	2016
Total unrecognized compensation cost (in millions)	$ -	$ 0.0
Recognition period	-	-
Fair value	$ -	$34.00

A summary of time-vested restricted stock activity under the plan for 2016 is presented in the table below:

	2016	
	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	55,600	$24.60
Granted	18,400	$29.53
Distributed	(18,500)	$21.36
Forfeited	-	-
Outstanding at December 31,	55,500	$27.31

Pursuant to the Merger Agreement, and concurrent with the closing of the Merger, 37,162 shares of time-vested restricted stock grants that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment, payable in accordance with the Merger Agreement. The cancellation and conversion of these shares are not included in the table above. See Note 15 for further discussion of the Merger Agreement.

Performance-Based Restricted Stock Awards

Prior to the Merger, performance-based restricted stock awards were granted to qualified individuals consisting of the right to receive a number of shares of common stock at the end of the restricted period assuming performance criteria are met. The performance measure for the award was the total return to our stockholders over a three-year period compared with an investor-owned utility peer group. The threshold level of performance under the 2014, 2015 and 2016 grants was set at the 20th percentile level of the peer group, target at the 50th percentile level, and the maximum at the 80th percentile level. Shares would be earned at the end of the three-year performance period as follows: 100% of the target number of shares if the target level of performance is reached, 50% if the threshold is reached, and 200% if the percentile ranking is at or above the maximum, with the number of shares interpolated between these levels. However, no shares would be payable if the threshold level is not reached.

If employment terminated during the performance period because of death, retirement, or disability, the individual was entitled to a pro-rata portion of the performance-based restricted stock awards such individual would otherwise have earned. If employment was terminated during the performance period for reasons other than those listed above, the performance-based restricted stock awards would be forfeited on the date of the termination unless the Compensation Committee of the EDE Board of Directors determined, in its sole discretion, that the individual was entitled to a pro-rata portion of such award. In addition, if a change in control occurs during the performance period, a pro-rata portion of the target performance-based restricted stock awards will vest and be distributed upon such change in control. At the end of the performance period, the number of shares earned, determined without regard to the special change in control vesting provisions will be determined and such amount, less the number of shares distributed upon the change in control, shall be distributed. Our Merger with Liberty Central triggered a change in control and the distribution is described below.

Pursuant to the Merger Agreement, shares were revalued during 2016 to $34.00 per share in accordance with the Merger Agreement.

Non-vested performance-based restricted stock awards (based on target number) as of December 31, 2016 and changes during the year ended December 31, 2016 were as follows:

	2016	
	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1	69,021	$24.38
Target shares granted	22,400	$29.53
Shares issued in excess of target	18,403	$21.36
Shares awarded	(43,036)	$21.36
Forfeited shares	-	-
Target shares not awarded	-	-
Nonvested at December 31	66,788	$27.22

At December 31, 2016, all compensation expense related to estimated outstanding awards had been recognized.

Pursuant to the Merger Agreement, and concurrent with the closing of the Merger, 42,600 shares of performance-based restricted stock granted under the 2006 SIP and the 2015 SIP that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment, payable in accordance with the Merger Agreement. The cancellation and conversion of these shares are not included in the table above. See Note 15 for further discussion of the Merger Agreement.

Stock Unit Plan for EDE Directors

Prior to the closing of the Merger, our Stock Unit Plan for Directors (SUP) provided a stock-based compensation program for EDE directors. The SUP provided EDE Directors the opportunity to convert previously earned cash retirement benefits to common stock units. All eligible Directors who had benefits under the prior cash retirement plan converted their cash retirement benefits to common stock units.

The number of units granted annually was computed by dividing an annual credit (determined by the Compensation Committee) by the fair market value of our common stock on January 1 of the year the units are granted. Common stock unit dividends were computed based on the fair market value of our stock on the dividend's record date. We recorded the related compensation expense at the time we made the accrual for the Directors' benefits as the Directors provided services. Shares accrued to Directors' accounts and shares available for issuance under this plan at December 31 are shown in the table below:

	2016
Shares accrued to EDE directors' accounts	211,588
Shares available for issuance	656,737

Units accrued for service and dividends as well as units redeemed for common stock at December 31 are shown in the table below:

	2016
Units accrued for service and dividends	47,747
Units redeemed for common stock	21,246

As a result of the timing of the closing of the Merger, 20,331 units were accrued to directors' accounts on December 31, 2016 for service and dividends.

Algonquin offers a Performance Stock Unit (PSU) plan to officers and directors as part of its long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2% to 237% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the consolidated balance sheet date. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date. Our compensation expense for 2017 was $0.1 million.

9. INCOME TAXES

Income tax expense components for the years ended December 31 are as follows (in thousands):

	2017	2016
Current income taxes:		
Federal	$ (188)	$ 739
State	2,494	-
TOTAL	2,306	739
Deferred income taxes:		
Federal	48,261	33,708
State	6,874	4,801
TOTAL	55,135	38,509
Investment tax credit amortization	(143)	(143)
TOTAL INCOME TAX EXPENSE	**$ 57,298**	**$ 39,105**

Deferred Income Taxes

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows (in thousands):

Deferred Income Taxes	December 31, 2017	December 31, 2016
NET DEFERRED TAX LIABILITIES	$ 277,013	$ 429,666

Temporary differences related to deferred tax assets and deferred tax liabilities are summarized as follows (in thousands):

Temporary Differences	December 31, 2017	December 31, 2016
Deferred tax assets:		
Plant related basis differences	$ 20,457	$ 28,531
Net operating loss (NOL)	-	17,869
Regulated liabilities related to income taxes	62,176	12,939
Disallowed plant costs	1,340	1,612
Gains on hedging transactions	718	1,131
Carry forward of income tax credit	1,808	8,675
Other	1,454	2,289
Total deferred tax assets	$ 87,953	$ 73,046
Deferred tax liabilities:		
Depreciation, amortization and other plant-related differences	$ 305,501	$ 426,137
Regulated assets related to income	26,868	38,927
Loss on reacquired debt	2,059	3,316
Amortization of intangible assets	8,272	11,207
Pensions and other post-retirement benefits	5,043	7,957
Deferred construction accounting costs	3,632	5,576
Other	13,591	9,592
Total deferred tax liabilities	364,966	502,712
NET DEFERRED TAX LIABILITIES	**$ 277,013**	**$ 429,666**

Effective Income Tax Rates

The difference between income taxes and amounts calculated by applying the federal legal rate to income tax expense for continuing operations were as follows:

Effective Income Tax Rates	2017	2016
Federal statutory income tax rate	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:		
State income tax (net of federal benefit)	3.1	3.1
Investment tax credit amortization	(0.4)	(0.4)
Effect of rate-making on property related differences	2.5	(0.6)
Federal income tax rate reduction (TCJA)	(7.0)	-
Transaction-related costs	26.9	-
Other	0.8	0.8
EFFECTIVE INCOME TAX RATE	**60.9%**	**37.9%**

The increase in our effective income tax rate for 2017 is driven by significant transaction-related costs incurred in connection with our acquisition by Liberty Utilities that are not deductible for tax purposes and the impacts of U.S. federal income tax reform, discussed further below.

We do not have any unrecognized tax benefits as of December 31, 2017. We did not recognize any significant interest or penalties in any of the periods presented. We do not expect any significant changes to our unrecognized tax benefits over the next twelve months.

Tax information included in these consolidated financial statements reflects the results of operations of the Empire District companies on a standalone basis. Due to our acquisition on January 1, 2017, we plan on joining the Liberty Utilities consolidated group for filing federal and state income tax returns. As such, Empire’s current income and carried forward tax attributes will be combined with those of the other Liberty Utilities companies.

At the beginning of 2016, we had a net operating loss (NOL) carryforward of $32.5 million. In 2016, we generated an additional NOL of $11.9 million resulting primarily from bonus depreciation on the Riverton 12 facility placed into service during the year. During 2017, on a standalone basis, we consumed the entire $44.4 million NOL carryforward.

In 2010, we received $17.7 million of investment tax credits based on our investment in Iatan 2, which, if unused, will expire in 2030. We utilized $10.4 million of these credits in the 2013 tax year. In 2017, on a standalone basis, we utilized $5.4 million of the credits, leaving a remaining carryforward of $1.8 million to offset future tax liabilities. The tax credits will have no significant income statement impact because they will flow to our customers as we amortize the tax credits over the life of the plant.

Federal Tax Reform

The “Tax Cuts and Jobs Act” (TCJA) was enacted on December 22, 2017. Substantially all of the provisions of the TCJA affecting the Company, other than certain transition depreciation rules, are effective for taxable years beginning after December 31, 2017. The TCJA includes significant changes to the Internal Revenue Code, including amendments that significantly change the taxation of business entities and specific provisions related to regulated public utilities. The most significant change that affects the Company is the reduction in the federal corporate statutory income tax rate from 35% to 21%. Specific provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of accelerated depreciation tax benefits from certain regulated utility capital investments acquired after September 27, 2017, and the continuation of certain rate normalization requirements related to the flow back of excess deferred taxes.

In accordance with GAAP, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted. GAAP also requires deferred tax assets and liabilities to be measured at the tax rate that is expected to apply when temporary differences are realized or settled. Thus, in December 2017, the Company’s deferred taxes were revalued using the new tax rate. To the extent deferred tax balances are included in rate base, the revaluation of deferred taxes was deferred as a regulatory liability on the consolidated balance sheets and will be refunded to customers. For deferred tax balances not included in rate base, the revaluation of deferred taxes was recorded as income tax expense.

As a result of the complexity of the TCJA, the Securities and Exchange Commission (SEC) staff issued guidance to clarify the accounting for income taxes if information is not yet available or complete. This guidance provides for up to a one-year period in which to complete the required analysis and update provisional estimates. The guidance provides three scenarios associated with a company's status of accounting for income tax reform: (1) a company has completed its accounting for certain effects of tax reform, (2) a company is able to make a reasonable estimate for certain effects of tax reform and records that estimate as a provisional amount, or (3) a company is not able to make a reasonable estimate and therefore continues to apply income tax accounting that is based on the tax laws in effect immediately prior to the enactment of the TCJA.

As of December 31, 2017, the Company has made reasonable estimates for the measurement and accounting of certain effects of the TCJA, which have been reflected in its consolidated financial statements. We have recorded provisional estimates which may be revised during the one-year analysis period. Additionally, interpretations, regulations, amendments, and technical corrections of the TCJA by various regulators could also resolve provisional items. The TCJA had the following provisional effects for the year ended December 31, 2017:

Increase (decrease)	
Accumulated deferred income taxes, net	$(213,817)
Income tax expense (benefit)	(5,897)
Noncurrent regulatory liabilities	207,920

For our regulated operations, reductions in accumulated deferred income tax balances due to the reduction in the federal statutory corporate income tax rate to 21% will result in amounts previously collected from utility customers for these deferred taxes being refundable to those customers, generally through reductions in future rates. The TCJA includes provisions related to the IRS normalization rules that address the time period in which certain plant-related components of the excess deferred taxes are to be reflected in customer rates. This time period for the Company is approximately 40 years. Other components of the excess deferred taxes will be reflected in customer rates as determined by our state and federal regulators, which could be a shorter time period than that applicable to certain plant-related components.

10. COMMONLY OWNED FACILITIES

Iatan

We own a 12% undivided interest in the coal-fired Units No. 1 and No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. We are entitled to 12% of each unit's available capacity and are obligated to pay for a like percentage of the operating costs of the units. KCP&L and KCP&L Greater Missouri Operations Co. own 70% and 18% respectively, of Unit 1, and 54% and 18%, respectively, of Unit 2. KCP&L operates the units for the joint owners.

At December 31, 2017 and 2016, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	**2017**	**2016**
Cost of ownership in plant in service	$ 391.3	$ 381.3
Accumulated depreciation	$ 116.8	$ 112.3
Expenditures[1]	$ 28.8	$ 27.1

[1] Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

State Line Combined Cycle Unit

We share joint ownership with Westar Generating, Inc, (WGI), a subsidiary of Westar Energy, Inc., of a nominal 500-megawatt combined cycle unit at the State Line Power Plant (State Line Combined Cycle Unit). We are responsible for the operation and maintenance of the State Line Combined Cycle Unit, and are entitled to 60% of the available capacity and are responsible for approximately 60% of its costs.

At December 31, 2017 and 2016, our property, plant and equipment accounts included the amounts in the following chart (in millions):

State Line Combined Cycle Unit	**2017**	**2016**
Cost of ownership in plant in service	$ 163.5	$ 162.8
Accumulated depreciation	$ 47.5	$ 44.8
Expenditures[(1)]	$ 41.8	$ 36.6

(1) Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

Plum Point Energy Station

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 7.52% of the station's capacity, and are obligated to pay for a like percentage of the station's operating costs.

At December 31, 2017 and 2016, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	**2017**	**2016**
Cost of ownership in plant in service	$ 109.7	$ 109.2
Accumulated depreciation	$ 15.0	$ 13.8
Expenditures[(1)]	$ 9.1	$ 10.0

(1) Recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

All of the dollar amounts listed above represent our ownership share of costs.

11. COMMITMENTS AND CONTINGENCIES

We are a party to various claims and legal proceedings arising out of the normal course of our business. We regularly analyze this information, and provide accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the Company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

Proceedings in connection with the Merger with Liberty Central

On March 24, 2016, a stockholder of Empire filed a complaint styled as a class action lawsuit. The complaint alleged that Empire's Board of Directors breached its fiduciary duties in agreeing to the Merger Agreement by, among other things, conducting an inadequate sales process and failing to obtain adequate consideration, having an interest in completing the Merger, and failing to make adequate disclosures in the proxy statement. The complaint sought various relief, including an injunction against the Merger. The complaint also alleges that Empire, APUC, Liberty Central and Merger Sub aided and abetted the alleged breaches.

On June 7, 2016, Empire and other defendants entered into a Memorandum of Understanding (MOU) providing for the settlement, subject to court approval, of all claims asserted in the complaint against all defendants. Empire and the other defendants that entered into the MOU did so solely to avoid the costs, risks and uncertainties inherent in litigation and without admitting any liability or wrongdoing and continue to vigorously deny that they committed any violation of law or engaged in any wrongful acts alleged in the complaint.

The proposed settlement provides for the release of any and all claims arising out of or relating to the Merger. Empire has incurred its full retention, $0.5 million, and its insurer has accepted responsibility for Empire's liability that exceeds its retention in connection with the lawsuit. The parties have reached a proposed settlement concerning all matters.

The final settlement hearing was delayed to allow a Special Master appointed by the Court to make a report concerning the proposed settlement. The Special Master has recommended against approval of the settlement terms agreed to between the parties because he challenges whether the plaintiffs, as a class, have received sufficient benefit from additional disclosures made through the class action lawsuit to foreclose all future claims of class members.

The outcome of the lawsuit cannot be predicted with any certainty, but Empire is believed to have reached the extent of its liability. An injunction could result in the unwinding of the Merger, although Empire believes that to be extremely unlikely. All of the defendants believe that the claims asserted against them in the lawsuit are without merit.

Coal, Natural Gas and Transportation Contracts

The following table sets forth our firm physical gas, coal and transportation contracts for the periods indicated as of December 31, 2017 (in millions):

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
January 1, 2018 through December 31, 2018	$ 24.9	$ 4.0
January 1, 2019 through December 31, 2020	40.2	2.2
January 1, 2021 through December 31, 2022	26.3	-
January 1, 2023 and beyond	38.5	-

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. The minimum requirements for our coal and coal transportation contracts as of December 31, 2017 are detailed in the table above. Our existing railroad agreement was modified and became effective on October 1, 2016. Our contractual obligations, as reflected in the table above, were reduced as a result of the amendment. The amended terms continue to allow us to operate the Asbury plant up to full load capacity.

Purchased Power

We have three purchased power agreements.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit’s capacity. We also have a long-term agreement for the purchase of an additional 50 megawatts of capacity from Plum Point. Commitments under this agreement are approximately $257.3 million through August 31, 2039, the end date of the agreement.

We have a long-term purchased power agreement, which expires in 2028, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a long-term contract, which expires in 2025, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

We do not own any portion of these windfarms. Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations shown below.

New Construction

There were no major construction projects in 2017.

In April 2016, we completed the conversion of Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion included the installation of a heat recovery steam generator (HRSG), steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. Final construction costs were $168.1 million for the project, excluding AFUDC. This amount was included in our five-year capital expenditure plan.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for one unit train to meet coal delivery demand for our electric segment and for one office facility related to our gas segment. The electric segment has 95 land leases for future wind project facilities that are for a seven-year lease term during the development period of the project, after which there are renewal terms at higher rates for sites that are developed. There are also 14 lease options for future wind project facilities that are for a three-year lease term that the Company has the right to terminate at any time. In addition, we have capital leases for certain office equipment and 106 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases totaled $5.2 million at December 31, 2017.

Our lease obligations over the next five years are as follows (in thousands):

	Capital Leases	**Operating Leases**
2018	$ 541	$ 893
2019	540	722
2020	537	237
2021	537	237
2022	537	237
Thereafter	1,368	355
Total minimum payments	**4,060**	**$2,681**
Less amount representing interest	852	
Present value of net minimum lease payments	**$3,208**	

Expenses incurred related to operating leases were $0.8 million for 2017 and 2016, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $2.5 million and $2.2 million at December 31, 2017 and 2016, respectively.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect these costs to be material, although recoverable in rates.

Compliance Plan

In order to comply with current and forthcoming environmental regulations, we implemented our compliance plan and strategy (2013 Compliance Plan), which largely follows our Integrated Resource Plan (IRP) filed with the MPSC in mid-2013. On April 1, 2016, we filed our updated IRP, reflecting the completion of our 2013 Compliance Plan. The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), were the drivers behind our 2013 Compliance Plan and its implementation and completion schedule. Compliance costs we have incurred associated with the MATS, CAIR and CSAPR regulations are being recovered in our rates and we anticipate any future costs to continue to be recoverable in our rates.

The following list summarizes the most significant environmental regulations affecting our operations:

Regulations
Air Emissions - NOx and SO2
ACID RAIN
CAIR (Clean Air Interstate Rule)
CSAPR (Cross State Air Pollution Rule)
MATS (Mercury Air Toxic Standards)
NAAQS (National Ambient Air Quality Standards)
Greenhouse Gases (GHGs) – CO_2
Surface Impoundments
Coal Ash Impoundments:
Water Discharges

MATS: As noted above, the completion of our Compliance Plan puts us in compliance with MATS. Although the regulation has been challenged, MATS has remained in place, and a final supplemental finding issued on April 14, 2016 completed the Environmental Protection Agency's (EPA) requirements. The final Technical Corrections Rule was signed March 17, 2016.

Greenhouse Gases: The EPA's 2015 rule for limiting carbon emissions from existing power plants (the Clean Power Plan or CPP) continues to undergo legal challenges. On October 10, 2017, the EPA proposed to repeal the CPP and accepted comments through January 16, 2018. In addition, the EPA held public hearings on the proposed repeal on November 28th and 29th, 2017.

An Advanced Notice of Public Rulemaking (ANOPR) to solicit information from the public about potential future rulemaking to limit greenhouse gas emissions for existing electric utility steam generating units (EGUs) was published on December 18, 2017 by the EPA. The EPA is accepting comments on this ANOPR until February 26, 2018.

Surface Impoundments: The EPA's final revision of the Clean Water Act (CWA) Steam Electric Effluent Limitation Guidelines (ELGs) for coal-fired power plants set technology-based ELGs based on the nature of the pollutants being discharged and the facilities involved. As published, beginning in November 2018, the EPA and states will begin to incorporate the new standards into all wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs at each affected facility that will result from the new standards to be in effect no later than December 2023.

The EPA's final rule to regulate the disposal of coal combustion residuals (CCRs) as a non-hazardous solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA) impacts our Asbury plant. Compliance with both the CCR and ELG rules at Asbury is expected to require the closure of the existing ash impoundment, construction of a new utility waste landfill and conversion of the existing bottom ash handling from a wet to a dry system. Final closure of the existing ash impoundment, for which an asset retirement obligation of $15.5 million has been recorded, is anticipated after the new landfill is operational. Separately, an asset retirement obligation of $4.4 million has been recorded for our interest in the coal ash impoundment at the Iatan Generating Station.

On December 28, 2016, the Missouri Department of Natural Resources (MDNR) approved our permit application to construct a utility waste landfill on a 217-acre site adjacent to the Asbury plant.

At this time, we anticipate CCR/ELG compliance costs to be approximately $15-$30 million. This estimate is based on our current capital budget, information gathered to date in relation to the multiple CCR Rule reports, and the current execution plan. As we move forward through the ELG and CCR rules' timelines of compliance, these plans may change. Currently, the landfill construction and bottom ash conversion are anticipated to be complete by early 2019. The CCR impoundment will be closed within five years after inactivity. We expect compliance costs to be recoverable in our rates.

Water Discharges: We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits.

The EPA final rule under the CWA Section 316(b) for existing cooling water intake structures became effective on October 14, 2014. An industry coalition has filed an appeal of the rule and additional court challenges are expected. We expect the regulations to have no future impact at Riverton as the new intake structure design and installed cooling tower, as part of the Unit 12 conversion, meets the regulatory requirement for aquatic life protections. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Iatan Unit 2 and Plum Point Unit 1 are covered by the regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally affected by the final rule.

Renewable Energy

The Missouri Clean Energy Initiative (Proposition C) requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014-2017, at least 10% in 2018-2020 and at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of generation from our Ozark Beach Hydroelectric Project and purchased power agreements previously mentioned with Cloud County Windfarm, LLC and Elk River Windfarm, LLC. Proposition C also requires that 2% of the energy from renewable energy sources must be solar. On May 6, 2015, the MPSC approved tariffs we filed on May 5, 2015 to establish solar rebate payment procedures and revise our net metering tariffs to accommodate the payment of solar rebates. We expect solar rebates to be sufficient to allow compliance with the current 2% requirement. As of December 31, 2017, we had processed 1,255 solar rebate applications resulting in solar rebate-related costs totaling approximately $13.0 million under the new tariff. We have recorded the $13.0 million as a regulatory asset (See Note 3). The law provides a number of methods that may be utilized to recover the associated expenses. We expect any costs to be recoverable in rates.

12. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

We engage in hedging activities in an effort to minimize our risk from the volatility of natural gas prices and power cost risk associated with exposure to congestion costs. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain cost predictability.

We acquire TCRs in an effort to mitigate the cost of power we purchase from the SPP IM due to congestion exposure. TCRs entitle the holder to a stream of revenues (or charges) based on the day-ahead congestion on the transmission path. TCRs can be purchased or self-converted using rights allocated based on prior investments made in the transmission system. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All financial derivative instruments are recognized at fair value on the consolidated balance sheets (See Note 1). The unrealized losses or gains from derivatives used to hedge our fuel and purchased power costs in our electric segment are recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those gains or losses are probable of refund or recovery, respectively, through our fuel adjustment mechanisms.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instruments in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our consolidated statement of income and subject to our fuel adjustment mechanism.

As of December 31, 2017 and 2016, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments held as of December 31, (in thousands):

ASSET DERIVATIVES		2017	2016
Non-Designated Hedging Instruments Due to Regulatory Accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current assets	$ 20	$ 326
	Noncurrent assets and deferred charges-Other	-	-
Natural gas contracts, electric segment	Current assets	-	3,223
	Noncurrent assets and deferred charges-Other	53	684
Transmission congestion rights, electric segment	Current assets	6,227	2,492
Total derivative assets		**$ 6,300**	**$ 6,725**

LIABILITY DERIVATIVES		2017	2016
Non-Designated as Hedging Instruments Due to Regulatory Accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current liabilities	$ 89	$ 17
	Non-current liabilities and deferred credits	71	-
Natural gas contracts, electric segment	Current liabilities	1,397	1,126
	Noncurrent liabilities and deferred credits	638	1,239
Transmission congestion rights, electric segment	Current liabilities	-	-
Total derivative liabilities		**$ 2,195**	**$ 2,382**

Electric Segment

At December 31, 2017, approximately $1.4 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months.

The following tables set forth “mark-to-market” pre-tax gains/(losses) from non-designated derivative instruments for the electric segment for each of the years ended December 31 (in thousands):

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Balance Sheet Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2017	**2016**
Commodity contracts	Regulatory (assets)/liabilities	$ (5,892)	$ 6,810
Transmission congestion rights	Regulatory (assets)/liabilities	20,909	6,761
Total – Electric Segment		**$ 15,017**	**$ 13,571**

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Statement of Operations Classification of Gain/(loss) on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative	
		2017	2016
Commodity contracts	Fuel and purchased power expense	$ (1,503)	$ (3,269)
Transmission congestion rights	Fuel and purchased power expense	22,285	5,508
Total – Electric Segment		**$ 20,782**	**$ 2,239**

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

As of December 31, 2017, the following volumes and percentage of our anticipated volume of natural gas usage for our electric operations for 2018 and the next four years are shown below at the following average prices per Dekatherm (Dth). We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long-term uncertainty (including with respect to required volumes and counterparty credit) are also considered.

		Dth Hedged			Procurement
Year	% Hedged	Physical	Financial	Average Price	Guidelines
2018	59%	3,745,006	5,960,000	$ 2.985	Up to 100%
2019	38%	3,380,000	3,460,000	$ 2.628	60%
2020	19%	1,840,000	1,500,000	$ 2.789	40%
2021	12%	-	2,000,000	$ 2.900	20%
2022	-%	-	-	$ -	10%

At December 31, 2017, the following TCRs have been obtained from TCR auctions to hedge congestion costs in the SPP IM:

Year	Monthly MWH Hedged	$ Value
2018	4,232	$ 6,227

Gas Segment

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of December 31, 2017, we had 1.2 million Dths in storage on the three pipelines that serve our customers. This represents 59% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the ACA year at September 1 and illustrates our hedged position as of December 31, 2017 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	-	-	1,195	65%
Second	Up to 50%	560	-	-	15%
Third	Up to 20%	560	-	-	15%

A PGA clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our consolidated balance sheets.

The following table sets forth "mark-to-market" pre-tax gains/(losses) from derivatives not designated as hedging instruments for the gas segment for the years ended December 31 (in thousands):

Non-Designated Hedging Instruments Due to Regulatory Accounting – Gas Segment	Balance Sheet Classification of Loss on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2017	2016
Commodity contracts	Regulatory (assets)/liabilities	$ (427)	$ 920
Total – Gas Segment		**$ (427)**	**$ 920**

Contingent Features

Certain of our derivative instruments contain provisions that are triggered if we fail to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. We had no derivative instruments with the credit-risk-related contingent features in a net liability position on December 31, 2017 and have posted no collateral with counterparties in the normal course of business. Amounts reported as margin deposit assets represent our funds held on deposit for our contracts held with our NYMEX broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at the dates shown. There were no margin deposit liabilities at these dates.

(in millions)	December 31, 2017	December 31, 2016
Margin deposit assets	$ 4.6	$ 1.5

Offsetting of derivative assets and liabilities

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from a default under derivatives agreements by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; and (2) the North American Energy Standards Board Inc. Agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Collateral requirements are calculated at the master trading and netting agreement level by the counterparty.

As shown above, our asset and liability commodity contract derivatives are reported at gross on the consolidated balance sheets. ASC guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. For the years ended December 31, 2017 and December 31, 2016, we did not hold any collateral posted by our counterparties. The only collateral we have posted is our margin deposit assets described above. We have elected not to offset our margin deposit assets against any of our eligible commodity contracts.

13. FAIR VALUE MEASUREMENTS

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data.

The guidance also requires that the fair value measurement of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g., collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the consolidated financial statements.

Our TCR positions, which are acquired on the SPP IM, are valued using the most recent monthly auction clearing prices. Our commodity contracts are valued using the market value approach on a recurring basis. The following fair value hierarchy table presents information about our TCR and commodity contracts measured at fair value as of December 31:

($ in 000's)		Fair Value Measurements at Reporting Date Using		
Description	Assets/(Liabilities) at Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		December 31, 2017		
Derivative assets	$ 6,300	$ 73	$ 6,227	$ -
Derivative liabilities	$ (2,195)	$ (2,195)	$ -	$ -
		December 31, 2016		
Derivative assets	$ 6,725	$ 4,233	$ 2,492	$ -
Derivative liabilities	$ (2,382)	$ (2,382)	$ -	$ -

*The only recurring measurements are derivative related.

Other fair value considerations

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions.

The carrying amount of our total long-term debt exclusive of capital leases at December 31, 2017 and 2016 was $827 million and $826 million, compared to a fair market value of approximately $926 million and $839 million, respectively. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of December 31, 2017 or that will be realizable in the future.

14. REGULATED OPERATING EXPENSE

The following table sets forth the major components comprising "regulated operating expenses" under "operating revenue deductions" on our consolidated statements of income for the years ended (in thousands):

	December 31, 2017	December 31, 2016
Power operation expense (other than fuel)	$ 17,916	$ 17,110
Electric transmission and distribution expense	29,478	27,751
Natural gas transmission and distribution expense	2,321	2,543
Customer accounts and assistance expense	12,069	11,123
Employee pension expense [1]	12,300	11,859
Employee healthcare plan [1]	11,342	10,125
General office supplies and expense	10,510	17,209
Administrative and general expense	23,774	14,580
Bad debt expense	1,880	1,452
Miscellaneous expense	362	377
TOTAL	$ 121,952	$ 114,129

(1) Does not include capitalized portion of costs, but reflects the GAAP expensed cost plus or minus costs deferred to and amortized from a regulatory asset and/or a regulatory liability for Missouri, Kansas and Oklahoma jurisdictions.

15. MERGERS AND ACQUISITIONS

Merger with Liberty Utilities (Central) Co. and Liberty Sub Corp.

On February 9, 2016, Empire entered into an Agreement and Plan of Merger (the Merger Agreement) with Liberty Utilities Central, a Delaware corporation (Liberty), and Merger Sub, a Kansas corporation, providing for the merger of Merger Sub with and into Empire, with Empire surviving the merger as a whollyowned subsidiary of Liberty Central (The Merger). The Merger closed on January 1, 2017. Pursuant to the Merger Agreement, at the effective time of the Merger, each issued and outstanding share of Empire common stock (other than any shares owned by Empire or Algonquin Power & Utilities Corp. (APUC) or any of their respective subsidiaries or any shares for which appraisal rights have been perfected) was cancelled and converted automatically into the right to receive $34.00 in cash, without interest.

On June 16, 2016, Empire's stockholders voted to approve the merger. All required regulatory approvals and consents were also received in 2016. In connection with each of the regulatory approvals received, Liberty Utilities Co. agreed to certain commitments regarding ongoing service to Empire customers, employment of Empire personnel, cost-sharing mechanisms, and compliance with existing regulatory stipulations in the normal course of business.

Pursuant to the Merger Agreement, and subsequent to the closing of the Merger, 37,162 shares of time-vested restricted stock grants that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment equal to $34.00 per share. Payment of the lump-sum cash awards were made in January 2017 and totaled approximately $1.3 million.

Additionally, 42,600 shares of performance-based restricted stock granted under the 2006 SIP and the 2015 SIP that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment. In accordance with the Merger Agreement, the performance-based restricted stock was paid equal to $34.00 per share multiplied by the total number of shares of common stock that would have been earned for performance at "target" over the performance period under the grant. Payment of these lump-sum cash awards were made in January 2017 and totaled approximately $3.1 million.

In connection with entering into the Merger Agreement, Empire incurred approximately $8.9 million and $9.1 million of transaction costs during 2017 and 2016, respectively. We do not expect to incur significant transaction costs during 2018 as a result of the Merger, and do not expect regulatory recovery of these costs in any jurisdiction that we serve.

The Board of Directors adopted a Change In Control Severance Pay Plan (“Severance Plan”) in 1991, amended most recently in 2008, that covers the Company’s executive officers as well as other key employees who are not executive officers. The Severance Plan provides severance payments and other benefits upon involuntary or voluntary termination of employment after a change in control. The completion of the Merger on January 1, 2017 triggered certain aspects of the Severance Plan and certain officers elected voluntary termination in accordance with the Severance Plan. The Company has recorded approximately $33.2 million of Severance Plan related expenses in 2017 based on officer terminations. Payment of these Severance Plan expenses will occur over several years, in accordance with the schedules determined for each officer receiving the benefits.

We have evaluated subsequent events through March 29, 2018, the date the consolidated financial statements were available to be issued.

Test Year Ending June 30, 2018

Line No.	Tariff	Customer Class	Pro Forma Revenues Existing	Proposed Revenue Increase	Pro Forma Revenues Proposed
		(a)	(b)	(c)	(d)=(b)+(c)
1		Residential	$8,287,667	$1,330,388	$9,618,055
2		Commercial	2,130,279	83,564	2,213,843
3		Industrial	5,820,489	244,779	6,065,268
4		Street Lights	605,140	31,166	636,306
5		Public Authorities	0	0	0
6		Total Retail	$16,843,575	$1,689,897	$18,533,472

Test Year Ending June 30, 2018

Line No.	Tariff	Schedule	Average Customers	Sales (kWh)	Base Rate Revenue	Other Revenues	Revenue Adjustments	Existing Pro Forma Revenue	Existing Rev/Unit (c/kWh)	Proposed Pro Forma Revenue	Proposed Rev/Unit (c/kWh)	Revenue Increase	Percent Increase
			(a)	(b)	(c)	(d)	(e)	(f)=(c)+(d)+(e)	(g)=(c)/(b)	(h)=(f)+(j)	(i)=(h)/(b)	(j)	(k)
1		**Residential**											
2	RG	RG-Residential	5,544	62,362,298	$4,969,879	($15,665)	$163,251	$5,117,464	0.0797	$5,938,952	0.0952	$821,488	16.05%
3	RG - WAT	RG-Residential Water Heat	762	10,735,927	794,715	(2,420)	25,902	818,197	0.0740	949,539.0	0.0884	131,342	16.05%
4	RH	RH-Residential Total Electric	1,867	34,436,656	2,285,058	(6,647)	73,595	2,352,006	0.0664	2,729,564.0	0.0793	377,558	16.05%
5		**Total Residential**	**8,173**	**107,534,881**	**8,049,651**	**(24,732)**	**262,747**	**8,287,667**	**0.0749**	**9,618,055.0**	**0.0894**	**1,330,388**	**16.05%**
6		**Commercial**											
7	CB	CB-Commercial	1,185	18,430,731	1,841,135	(7,448)	63,108	1,896,795	0.0999	1,968,048.0	0.1068	71,253	3.76%
8	SH	SH-Small Heating	110	2,779,399	226,836	(844)	7,492	233,484	0.0816	245,795.0	0.0884	12,311	5.27%
9		**Total Commercial**	**1,294**	**21,210,130**	**2,067,971**	**(8,292)**	**70,600**	**2,130,279**	**0.0975**	**2,213,843.0**	**0.1044**	**83,564**	**3.92%**
10		**Industrial**											
11	GP	GP-General Power	106	38,200,653	2,872,849	(12,453)	104,877	2,965,274	0.0752	2,965,274.0	0.0776	-	0.00%
12	TEB	TEB-Total Electric Building	40	9,327,899	651,774	(2,599)	21,521	670,696	0.0699	695,891.0	0.0746	25,195	3.76%
13	PT	PT-Transmission	5	48,142,857	2,004,870	(6,861)	186,510	2,184,519	0.0416	2,404,103.0	0.0499	219,584	10.05%
14		**Total Industrial**	**150**	**95,671,409**	**5,529,493**	**(21,912)**	**312,908**	**5,820,489**	**0.0578**	**6,065,268.0**	**0.0634**	**244,779**	**4.21%**
15		**Muni. Street & Highway Lighting**											
16	SPL	SPL-Municipal St Lighting	0	1,554,951	122,320	(239)	52,832	174,913	0.0787	202,991.0	0.1305	28,078	16.05%
17	LS	LS-Special Lighting	33	1,462,318	398,294	(1,778)	14,472	410,988	0.2724	410,988.0	0.2811	-	0.00%
18	PL	PL-Private Lighting	19	154,007	18,533	32	674	19,239	0.1203	22,327.0	0.1450	3,088	16.05%
19		**Total Street and Highway Lighting**	**51**	**3,171,276**	**539,147**	**(1,985)**	**67,978**	**605,140**	**0.1700**	**636,306.0**	**0.2006**	**31,166**	**5.15%**
20		**Other Public Authority**											
21		**Total Other Public Authority**	**0**	**0**	**0**	**0**	**0**	**0**		**0**		**0**	
22		**Total Retail**	**9,669**	**227,587,696**	**$16,186,263**	**(56921.19)**	**$714,233**	**$16,843,575**	**0.0711**	**$18,533,472**	**0.0814**	**$1,689,897**	**10.03%**

Test Year Ending June 30, 2018

Line No.	Tariff	Customer Class	Pro Forma Revenues Existing	Proposed Revenue Increase	Pro Forma Revenues Proposed
		(a)	(b)	(c)	(d)=(b)+(c)
1	RG/RG/RH	Residential	$ -	$1,817,562	$1,817,562
2	CB/SH	Commercial	-	299,428	$299,428
3	GP/TEB/PT	Industrial	-	1,040,566	$1,040,566
4	SPL/PL/LS	Street Lights	-	8,810	$8,810
5		Public Authorities	-	-	-
6		Total Retail	$ -	$3,166,367	$3,166,367

Test Year Ending June 30, 2018

Line No.	Tariff	Schedule	Average Customers	Sales (kWh)	Base Rate Revenue	Other Revenues	Revenue Adjustments	Existing Pro Forma Revenue	Existing Rev/Unit (c/kWh)	Proposed Pro Forma Revenue	Proposed Rev/Unit (c/kWh)	Revenue Increase	Percent Increase
			(a)	(b)	(c)	(d)	(e)	(f)=(c)+(d)+(e)	(g)=(c)/(b)	(h)=(f)+(j)	(i)=(h)/(b)	(j)	(k)
1		**Residential**											
2	RG	RG-Residential	5,544	62,362,298				-	0.0000	$1,061,589	0.0170	$1,061,589	100.00%
3	RG - WATER	RG-Residential Water Heat	762	10,735,927				-	0.0000	181,701	0.0169	181,701	100.00%
4	RH	RH-Residential Total Electric	1,867	34,436,656				-	0.0000	574,273	0.0167	574,273	100.00%
5		**Total Residential**	**8,173**	**107,534,881**				**-**	**0.0000**	**1,817,562**	**0.0169**	**1,817,562**	100.00%
6		**Commercial**											
7	CB	CB-Commercial	1,185	18,430,731				-	0.0000	255,633	0.0139	255,633	100.00%
8	SH	SH-Small Heating	110	2,779,399				-	0.0000	43,796	0.0158	43,796	100.00%
9		**Total Commercial**	**1,294**	**21,210,130**				**-**	**0.0000**	**299,428**	**0.0141**	**299,428**	100.00%
10		**Industrial**											
11	GP	GP-General Power	106	38,200,653				-	0.0000	435,155	0.0114	435,155	100.00%
12	TEB	TEB-Total Electric Building	40	9,327,899				-	0.0000	126,059	0.0135	126,059	100.00%
13	PT	PT-Transmission	5	48,142,857				-	0.0000	479,352	0.0100	479,352	100.00%
14		**Total Industrial**	**150**	**95,671,409**				**-**	**0.0000**	**1,040,566**	**0.0109**	**1,040,566**	100.00%
15		**Muni. Street & Highway Lighting**											
16	SPL	SPL-Municipal St Lighting	0	1,554,951				-	0.0000	4,932	0.0032	4,932	100.00%
17	LS	LS-Special Lighting	33	1,462,318				-	0.0000	3,741	0.0026	3,741	100.00%
18	PL	PL-Private Lighting	19	154,007				-	0.0000	137	0.0009	137	100.00%
19		**Total Street and Highway Lighting**	**51**	**3,171,276**				**-**	**0.0000**	**8,810**	**0.0028**	**8,810**	100.00%
20		**Other Public Authority**											
21		**Total Other Public Authority**	**-**	**-**	**-**	**-**	**-**	**-**		**-**		**-**	
22		**Total Retail**	**9,669**	**227,587,696**	**$ -**	**$ -**	**$ -**	**$ -**	**0.0000**	**$3,166,367**	**0.0139**	**$3,166,367**	**100.00%**

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE: Table of Contents

ALL TERRITORY
(Territory to which schedule is applicable)

Replacing Schedule Table of Contents Sheet 1
which was filed 02-23-15

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Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS	Index No. 1
THE EMPIRE DISTRICT ELECTRIC COMPANY (Name of Issuing Utility)	**SCHEDULE** RG
	Replacing Schedule RG Sheet 1
ALL TERRITORY (Territory to which schedule is applicable)	which was filed 01-01-12

RESIDENTIAL GENERAL SERVICE
SCHEDULE RG

Sheet 1 of 2 Sheets

AVAILABILITY:
This schedule is available for residential service to single-family dwellings or to multi-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$	17.00
For the first 600-Kwh used,	$	0.07920, per Kwh
Additional Kwh,	$	0.07058, per Kwh

WATER HEATING:
When one or more storage-type electric water heaters, with no more than 6,000 watts per heater operating on the line at any time, regularly in operation and is used to supply the Customer's total requirements for hot water, and the Customer so notifies the Company in writing, the Customer Charge will apply each month. For the Kwh each month, the first 600-Kwh of such use will be billed at $0.07341 per Kwh, and all in addition to 600-Kwh at the applicable rate as stated above.

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If this schedule is used for service through a single meter to multiple-family dwellings within a single building, each Kwh block will be multiplied by the number of dwelling units served in calculating each month's bill.

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/ Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 1

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE RH

Replacing Schedule RH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

RESIDENTIAL TOTAL ELECTRIC SERVICE
SCHEDULE RH
Sheet 1 of 1 Sheets

AVAILABILITY:
This schedule is available for residential service to Total Electric single-family dwellings or multiple-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$ 17.00
All Kwh at	$ 0.06626, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If used for service through a single meter to multiple-family dwellings within a single building, the first Kwh-use block and related charge will be multiplied by the number of dwelling units served in calculating each month's bill.
5. Welding, X-ray, or other equipment characterized by severe or fluctuating demands, will not be served.
6. Intermittent or seasonal service will not be provided.
7. Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE CB

Replacing Schedule CB Sheet 1

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

COMMERCIAL SERVICE
SCHEDULE CB

Sheet 1 of 1 Sheets

AVAILABILITY:

This schedule is available to any commercial or industrial Customer on the lines of the Company whose electric load is not in excess of 40 Kw, except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$ 20.00
The First 700 Kwh	$ 0.09589, per Kwh
For all additional Kwh used	$ 0.08534, per Kwh

PAYMENT:

All bills due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.
5. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.
6. The term of service will not be less than one (1) year. Intermittent or seasonal service will not be provided.
7 Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued December 7 2018
Month Day Year

Effective Upon Commission Approval
Month Day Year

By /s/ Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SH

Replacing Schedule SH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

SMALL HEATING SERVICE
SCHEDULE SH

AVAILABILITY:

This schedule is available to any general service customer on the lines of the Company whose electric load is not in excess of 40 Kw and where the electric service supplied is the only source of energy at the service location and the customer permanently installs and regularly uses electric space-heating equipment for all internal space-heating comfort requirements. However, this schedule is not available to those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$	20.00
The First 1000 Kwh used	$	0.08320, per Kwh
Additional Kwh	$	0.07341, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.

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THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE GP

Replacing Schedule GP Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

GENERAL POWER SERVICE
SCHEDULE GP

AVAILABILITY:
This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is purely for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:
DEMAND CHARGE:

First 40 Kw of Billing Demand	$	13.01, per Kw
Next 460 Kw of Billing Demand	$	10.38, per Kw
All additional Kw of Billing Demand	$	8.14, per Kw

ENERGY CHARGE:

For all Kwh	$	0.03397, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:
The Billing Demand will be the highest fifteen minute integrated kilowatt demand registered during the month by a suitable demand meter. In no event shall the Billing Demand be less than 40 Kw.

TRANSFORMER OWNERSHIP:
Where the Customer supplies all facilities (other than metering equipment) for utilization of service at the voltage of the Company's primary line feeding to such location, a discount of 5% will apply to the Demand Charge.

METERING ADJUSTMENT:
The above rate applies for service metered at secondary voltage. Where service is metered at the voltage of the primary line feeding to such location, adjustment for billing will be made by decreasing metered kilowatt hours by 3%.

MINIMUM MONTHLY BILL:
During any month in which service is rendered, the minimum monthly bill will be the Demand Charge.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE PT

Replacing Schedule PT Sheet 4

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

TRANSMISSION SERVICE
SCHEDULE PT

AVAILABILITY:
This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:
DEMAND CHARGE:

The first 1000-Kw of Billing Demand	$	13,158.00
All additional Kw of Billing Demand	$	6.22, per Kw

ENERGY CHARGE:

For all Kwh	$	0.02311, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:
The Billing Demand will be determined from the highest fifteen minutes integrated kilowatt demand registered during the month by a suitable demand meter, but no Billing Demand will be less than 65% of the highest such demand established during the year ending with the current month and in no event will the Billing Demand be less than 1000-Kw.

TRANSFORMER OWNERSHIP:
Service will be supplied at the voltage of the Company's primary system serving the area. Where the Company supplies a transformer for the utilization of service at a voltage lower than primary, the transformer will be charged as stated in Rider XC. If service is taken at transmission voltage available at such location, the demand charge will be reduced by 10%.

METERING ADJUSTMENT:
The above rate applies for service metered at primary voltage. Where service is metered at secondary voltage, an adjustment for billing will be made by increasing metered kilowatt hours by 3%. If metered at transmission voltage, metered kilowatt hours and demand will be reduced by 1%. Metering equipment other than standard primary metering will be charged as stated in Rider XC.

MINIMUM MONTHLY BILL:
The minimum bill for any month will be the Demand Charge.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

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Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS | Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE TEB

Replacing Schedule TEB Sheet 5

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

TOTAL ELECTRIC BUILDING SERVICE
SCHEDULE TEB
Sheet 1 of 2 Sheets

AVAILABILITY:
This schedule is available to any commercial or industrial Customers on the lines of the Company for total electric service except those Customers who are conveying electric service to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, etc., and others who provide transient room and/or room and board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

First 150-Kwh used, or less	$	32.00
Next 9,850-Kwh used	$	0.08723, per Kwh
All in addition to 10,000-Kwh used	$	0.06120, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.

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THE STATE CORPORATION COMMISSION OF KANSAS Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-01-12

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available to municipalities served by the Company under the provisions of an Electric Franchise having an original term of not less than ten (10) years, for outdoor lighting for streets, alleys, parks and public places under the provisions of the Company's standard MUNICIPAL ELECTRIC SERVICE AGREEMENT, having an original term of not less than two (2) years.

ANNUAL STREET LIGHTING CHARGE:

The charges below shall apply for street lighting systems (1) owned by the Municipality, or (2) installed, owned, operated and maintained by the Company, in accordance with a Facilities Usage Charge as hereinafter set forth.

		Watts
Mercury-Vapor Lamp Sizes: (FROZEN)		
7,000 lumen	$ 173.05	175
11,000 lumen	$ 202.36	200
20,000 lumen	$ 288.07	400
53,000 lumen	$ 469.17	1000
High-Pressure Sodium-Vapor Lamp Sizes (lucalox, etc.):		
6,000 lumen	$ 163.53	70
16,000 lumen	$ 205.99	150
27,500 lumen	$ 255.68	250
50,000 lumen	$ 375.95	400
130,000 lumen	$ 587.59	1000
Light Emitting Diode (LED) Fixtures:		
LED 1 7,500-9,500 lumen	$ 148.05	150
LED 2 13,000-16,000 lumen	$ 189.61	250
LED 3 19,000-22,000 lumen	$ 238.65	400

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA. The Energy Cost Adjustment for street lighting is computed by multiplying monthly burn hours use by the watts per lamp, listed above, times the Energy Cost Adjustment factor.

FACILITIES USAGE (INVESTMENT) CHARGE:

When, by agreement with the Municipality, the Company shall install, own, operate and maintain street lights served under this schedule or is required to provide special or excessive electric facilities to serve Municipality-owned street lighting systems served under this schedule, a separate agreement shall be executed by and between the Municipality and the Company setting forth the investment in such street lighting facilities and a Facilities Usage Charge in the amount of 1.5% per month of such investment. The Facilities Usage Charge shall be payable by the Municipality to the Company in the manner prescribed in the aforementioned separate agreement and in addition to the Street Lighting Charge as set forth herein.

DISCOUNT:

The total charges under this Schedule for Street Lighting and Facilities Usage shall be subject to a fifty percent (50%) discount plus an additional discount which shall be equal to one-half of one percent (0.5%) of the Annual Revenue received by the Company within the Municipality for a period of twelve (12) months ending December 31, from the Customers billed under Rate Schedules for Residential and Commercial service having a Billing Demand (Reserved Capacity) of 40 Kilowatts or less.

MINIMUM:

The total annual net amount of the Street Lighting Charge, plus the Investment Charge, shall not be less than an amount equal to twelve times the total of charges to the Municipality for street lighting service for the calendar month prior to the date of the contract.

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 01-04-06

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

PAYMENT:
All bills shall be rendered monthly at 1/12th the annual rates and shall be payable on or before the 25th day of each month succeeding the month during which service was rendered.

CONDITIONS OF SERVICE:
1. No new street lighting installation shall use Incandescent lamps.
2. No new individual lamp installation shall be less than 6,000 lumen.
3. All lamps shall burn every night from dusk to dawn, subject to a reasonable maintenance schedule.
4. The character of street lighting circuit (series or multiple) shall be determined by the Company.
5. If the Municipality owns the Street Lighting System, the Company will furnish electric energy, will inspect street lights, replace broken lamps or glassware (where applicable), and repaint steel poles when necessary. However, replacement or repairs to poles, conduit, cable, overhead conductors or fixtures other than glassware shall be paid for by the Municipality.

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THE STATE CORPORATION COMMISSION OF KANSAS	Index No. 3
THE EMPIRE DISTRICT ELECTRIC COMPANY (Name of Issuing Utility)	SCHEDULE LS
	Replacing Schedule LS Sheet 5
ALL TERRITORY (Territory to which schedule is applicable)	which was filed 01-01-12

SPECIAL LIGHTING SERVICE
SCHEDULE LS

AVAILABILITY:
This schedule is available for electric service to sport field lighting, carnival, circus or holiday decorative lighting or similar temporary or seasonal use.

MONTHLY RATE:

For the first 1,000 Kwh used	$	0.16158, per Kwh
For all additional Kwh used	$	0.11859, per Kwh

MINIMUM:
The net monthly minimum charge for any month during which electrical energy is used will be $39.60

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Service will normally be delivered and metered hereunder at the secondary voltage available at the service location. Where physical circumstances would normally make it necessary to meter the service at primary voltage, the Company may at its option install a time clock in place of primary metering facilities to measure the hours-use of the service and compute the kilowatt-hours' consumption of the sport field by using the Customer's connected load. The connected load used for the calculation will be determined at the time of installation and at such subsequent times as the Company may deem necessary by actual load check of the Customer's facilities.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed, or submetered, directly or indirectly.
3. In addition to the above charge, a Customer of temporary nature such as a carnival, circus, etc., will be required to pay the net cost of erection and removal of any special facilities necessary to provide service. Such net cost will include the Company's total expenditure for labor, material, supervision and all other costs necessary to erect and remove facilities for service, less proper credit for actual salvage.
4. Voltage, phase, and frequency of service supplied will be as approved by the Company.
5. Bills for service will be rendered monthly. Where service is for temporary use, the bill for the current month's service will be rendered immediately on discontinuance of service.
6. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

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THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed January 6, 2017

Sheet ____ of ____ Sheets

RESERVED FOR FUTURE USE

Commission File Number

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THE STATE CORPORATION COMMISSION OF KANSAS

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THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE TDC

Replacing Schedule ______ Sheet 13

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ______

TRANSMISSION DELIVERY CHARGE
RIDER TDC

Sheet 1 of 5 Sheets

APPLICABLILITY

This Transmission Delivery Charge (TDC) rider (Schedule TDC) shall be applicable to all Kansas Retail Rate Schedules for the Company.

BASIS OF CHARGE

Company shall collect from applicable customers a Transmission Delivery Charge (TDC) based on all transmission-related costs incurred to be recovered under the following schedules of the Open Access Transmission Tariff (OATT) offered by the Southwest Power Pool, Inc. (SPP) for service and the Midcontinent Independent System Operator (MISO) to the Company's retail customers:

SPP

- Schedule 1A – Tariff Administration
- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 9 – Network Integration Transmission Service
- Schedule 10 – Wholesale Distribution Service
- Schedule 11 – Base Plan Charge
- Schedule 12 – FERC Assessment Charge
- Monthly Assessment Charge

MISO

- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 2 – Reactive Supply and Voltage Control
- Schedule 7 – Long-Term Firm and Short-Term Firm Point-To-Point
- Schedule 10 – DERC Annual Charges Recovery
- Schedule 11 – Wholesale Distribution Service
- Schedule 26 – Network Upgrade Charge From Transmission Expansion Plan
- Schedule 33 – Blackstart Service
- Schedule 45 – Cost Recovery of NERC Recommendation or Essential Action

Other

- Other transmission-related charges recorded in FERC Account 565 (Transmission of Electricity by Others) and 557.4 (Pool Operation), fees charged to the Company by the North American Electric Reliability Council (NERC), and other transmission revenue requirements not otherwise reflected in and recoverable through base rates or other Commission authorized rider mechanisms shall be included.

The costs to be recovered under Schedule 9 (Network Integration Transmission Service) shall exclude the revenue requirement for all Company-owned transmission facilities classified by SPP as Base Plan Upgrades. Company shall provide periodic reports to the Commission of its collections, including a calculation of the total collected under this rate schedule.

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE TDC

Replacing Schedule ______ Sheet 13

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TRANSMISSION DELIVERY CHARGE
RIDER TDC

Method of Billing

The ATRR shall be collected by applying a TDC Unit Charge, developed for each rate schedule permitting such cost recovery, to each applicable customer's bill. The TDC Unit Charge shall be implemented using one or more of the following billing methods:

1. A dollar per kilowatt (KW) charge determined by dividing a portion of the cost of transmission service allocated to a rate schedule by the annual applicable KW sales for that rate schedule; and/or
2. A dollar per kilowatt hour (KWh) charge determined by dividing a portion of the cost of transmission service allocated to a rate schedule by the annual applicable KWh sales for that rate schedule.

The TDC Unit Charges included on the following sheets are designed to recover transmission-related charges incurred for the delivery of generation or as a result of serving native load from Kansas retail customers.

Transmission Delivery Charge Calculation:

The Company shall file an update on July 1 to its TDC Rates annually. The Company may file for a change in the TDR Rates more frequently than once per year.. All proposed TDC Rates shall be filed with the Commission no later than 30 business days before the effective date of the proposed charges. The TDC Rates will be established immediately following case 19-EPDE-XX-RTS but will be updated annually immediately following the filing and implementation of The Company's Transmission Formula Rate (TFR) filing.

TDC_{Filing} = SPP + MISO + Other + TU_{n-1}

TDC_{Actual} = SPP + MISO + Other + TU_{n-1}

TU_n = $TDC_{Actual} - TDC_{Rev}$

Where:

TDC Year = The 12-month period immediately following the implementation of The Company's TFR.

TDC_{Filing} = The TDC-related costs authorized by the Commission to be included in the development of the TDC Rates to be charged to Kanas Retail sales.

TDC_{Actual} = The TDC-related costs, as allocated to Kansas Retail sales, authorized to be recovered during the TDC year including the True-Up calculated for the prior TDC Year

TDC_{Rev} = Actual TDC Revenues for the Kansas Retail sales received during the TDC Year. These TDC revenues will be based in the TDC Rates in effect throughout the TDC Year. Such TDC Rates may be changed one or more times during the

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE TDC

Replacing Schedule ______ Sheet 13

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TRANSMISSION DELIVERY CHARGE
RIDER TDC

		TDC Year, with approval by the Commission. The TDC Rates in effect at any point during the TDC Year will be applied to Kansas Retail KWh sales or KW billing demands, as applicable, during the effective period of each such approved TDC Rate.
TU_n	=	True-Up calculation to reflect the difference between the actual TDC-related costs authorized to be recovered during the TDC Year and the actual TDC Revenues for Kansas Retail sales during the TDC Year. This True-Up will be applied to the TDC Rate for the following TDC Year.
TU_{n-1}	=	True-Up amount to reflect the difference between the actual TDC related costs authorized to be recovered during the prior TDC Year and the actual TDC Revenues for the Kansas Retail sales during the prior TDC Year. The difference for the prior TDC Year shall be included as a component of the TDC Rate for the current TDC Year.
		The TUn-1 component in the initial TDC Rate calculation for the initial TDC Year shall be equal to zero ($0). The True-Up component included in the TDC Rate calculations for subsequent TDC Years may be positive or negative.

Calculation of TDC Rates:

The Company shall calculate a separate TDC Rate for each applicable Kansas Retail Customer Class as described below:

$TDC_{KW\text{-}Rate(Class)}$ = $TDC_{Filing} \times DA_{Class} / KW_{Class}$

or

$TDC_{KWh\text{-}Rate(Class)}$ = $TDC_{Filing} \times DA_{Class} / KWh_{Class}$

Where:

$TDC_{KW\text{-}Rate(Class)}$	=	The TDC Rate applicable to General Power Service and Transmission Power Service and any other rate classes with a billing demand component.
$TDC_{KWh\text{-}Rate(Class)}$	=	The TDC Rate applicable to all Residential Services, Commercial Service, Small Heating Service, Total Electric Building Service, Lighting rate classes, and any remaining rate classes with only a KWh consumption component.

And:

TDC_{Filing} = Described in Sheet 3 under Transmission Delivery Charge Calculation

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THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** TDC
(Name of Issuing Utility)

Replacing Schedule Sheet 13

ALL TERRITORY
(Territory to which schedule is applicable) which was filed

TRANSMISSION DELIVERY CHARGE
RIDER TDC

DA_{Class} = The demand allocator for the applicable Kansas Retail customer class. This demand allocator shall be based on the 12-CP allocator utilized by the Company for its Class Cost of Service Study in its most recent Kansas retail rate case.

KW_{Class} = Class normalized Billing Demands (KW) utilized by the Company for its Rate Design Study in its most recent Kansas retail rate case.

KWh_{Class} = Class normalized Energy (KWh) utilized by the Company for its Rate Design Study in its most recent Kansas retail rate case.

The class demand allocators (DAClass), class normalized Billing Demands (KWClass), and class normalized Energy (KWhClass) shall remain unchanged, until the next general rate class in which class demand allocators and class normalized Billing Demands and Energy are reset or, at a minimum, once every five years, to limit cost shifting among retail classes.

Method of Billing

The TDC-related revenue requirements shall be collected by applying the TDC Rate, developed for each rate schedule permitting such cost recovery, to each applicable customer's bill. The TDC Rate shall be implemented using the applicable dollars per kilowatt-hour (KWh) charge or dollars per kilowatt (KW) charge.

TDC Rates Effective

The TDC Rates in the following table shall be applied to a customer's bill of each rate schedule as indicated. The amount determined by applying the TDC Rate shall become part of the total bill for electric service furnished and will be itemized separately on the customer's bill.

Rate Schedule	$ per KWh	$ per KW
Residential Service - RG	0.01702	
Residential Service - RGW	0.01692	
Residential Service - RH	0.01668	
Commercial Service - CB	0.01387	
Small Heating - SH	0.01576	
Total Electric Building - TEB	0.01351	
Lighting Service - SPL	0.00317	
Lighting Service - PL	0.00256	
Lighting Service - LS	0.00089	
General Power Service - GP		3.22346
Transmission Service - PT		4.28806

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE TDC

Replacing Schedule ______ Sheet 13

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TRANSMISSION DELIVERY CHARGE
RIDER TDC

Definitions and Conditions

The Company for the purposes of this rate schedule or rider is defined as The Empire District Electric Company.

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE RSR

Replacing Schedule ______ Sheet 14

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ______

REVENUE STABILIZATION RIDER
RIDER - RSR

PURPOSE

The purpose of this Rider is to stabilize customer bills and the Company's recovery of revenue requirements approved by the Commission in the most recent rate proceeding,

APPLICABILITY

This Rider is applicable to all customers served under Schedules Residential General (RG), Residential Heating (RH), Small Commercial Building Service (SH), and Small Commercial Total Electric Service (TEB). A separate adjustment shall be calculated for each applicable Schedule, expressed in cents per kWh.

The Revenue Stabilization adjustment shall be computed monthly for application on customer bills in the second succeeding month. It shall consist of a factor designed to reflect differences between actual base rate revenues and authorized base rate revenues approved in the most recent rate proceeding, plus a factor designed to reconcile prior period Revenue Stabilization adjustments.

The Revenue Stabilization adjustment can be a credit or charge that is applied to monthly bills. The Revenue Stabilization adjustment shall be combined with the Base Rates of the associated rate class and applied to customer bills.

CALCULATION OF REVENUE STABILIZATION ADJUSTMENT

The Revenue Stabilization adjustment shall be computed monthly by dividing the difference between the actual monthly revenue and authorized base rate revenues approved in the most recent rate proceeding by the forecast kWh sales for the applicable rate class for the second succeeding month. Authorized base rate revenues is defined as the base rate revenues approved by the Commission in the most recent rate proceeding.

$$RSA = \left[\frac{A - B + C}{D}\right]$$

where:

RSA	=	The monthly Revenue Stabilization adjustment factor for the rate class in $ per kWh
A	=	Actual Base Rate Revenues for the class
B	=	Authorized Base Rate Revenues for the class
C	=	Cumulative true-up for over/under-collection
D	=	Forecast kWh sales for the second succeeding month for the rate class

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Replacing Schedule ____ Sheet 14

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REVENUE STABILIZATION RIDER
RIDER - RSR

DEFINITIONS

"*Actual Base Rate Revenues*" represents the dollar amount of revenues by rate class arising from the base rates approved by the Commission in the most recent rate proceeding.

"*Authorized Base Rate Revenues*" represents the dollar amount of revenues by rate class approved by the Commission in the most recent rate proceeding.

"*Forecast kWh Sales*" represents the recovery period for the Revenue Stabilization adjustment as the forecast kWh sales for the second succeeding month

FILING

The Company shall file monthly with the Commission the Revenue Stabilization factors by rate class at least ten days prior to application on customer bills. The Company shall provide Commission Staff workpapers sufficient to review and audit the factors.

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SCHEDULE CR

Replacing Schedule ______ Sheet 15

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CAPITAL TRACKER RIDER
RIDER - CR

APPLICATION

To all bills rendered by the Company for utility service, permitting the recovery of such cost.

TERM:

This Capital Tracker will have a term beginning with the effective date of a Commission Order approving this Capital Tracker and ending with the rate effective date of the next general rate case, unless extended by the State Corporation Commission of Kansas ("Commission").

The Company will collect from customers as an adjustment to the aforementioned bills, an additional charge equal to the annual capital investment-related revenue requirements associated with investments qualified under this Capital Tracker ("Qualified Investments"). Qualified Investments include: (1) Grid Resiliency investments; (2) generation capacity; and (3) Other investments.

The calculation of such revenue requirements will be made in conformity with the formula stated in this Capital Tracker, and will not change absent Commission approval.

The Company shall provide periodic reports to the Commission of its collections including a calculation of the total collected under this Rider.

METHOD OF BILLING:

The additional charge shall be collected by applying the Capital Tracker charge to each applicable customer's bill. The Capital Tracker charges shall be based on the following method:

1. The Capital Tracker revenue requirement shall be allocated to each rate class consistent with the applicable cost allocator approved in the most recent rate proceeding. E.g., production-related investments costs shall be allocated based on the production plant allocator.

2. The Capital Tracker charges for each rate class shall be determined by dividing the Capital Tracker revenue requirements by the applicable billing units. The General Power and Transmission rate class shall be billed on a per kW basis, all other class shall be billed on a per kWh basis.

BASIS FOR DETERMINING THE CAPITAL TRACKER CHARGES:

The monthly charge shall reflect the recovery of the Capital Tracker revenue requirement as approved by the Commission. The Capital Tracker charge shall be implemented on an interim basis subject to refund and shall remain fixed until otherwise ordered by the Commission.

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE CR

Replacing Schedule ______ Sheet 15

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CAPITAL TRACKER
RIDER - CR

ANNUAL TRUE-UP:
The revenue collected pursuant to the application of this Capital Tracker shall be compared to the estimated revenue approved for collection by the Commission on an annualized basis. The amount of any over (under) recovery shall be included in any refund calculation that may result from the re-calculation of the revenue requirement to take place during Empire's next rate case.

INTERIM SUBJECT TO REFUND:
The revenue collected pursuant to this Capital Tracker, as approved by the Commission, shall be collected on an interim basis, subject to refund. For purposes of determining whether a refund is necessary, each component of the Capital Tracker revenue requirement will be determined by the Commission during Empire's next general rate case. The Capital Tracker revenue requirement will then be compared against the Capital Tracker revenue requirement approved by the Commission. If the Capital Tracker revenue requirement calculated by the Commission in Empire's next general rate case is less than the Capital Tracker revenue requirement approved by the Commission, then Empire shall refund the difference through a bill credit. The refund rates (bill credits) shall be distributed to customers in the same fashion as the original Capital Tracker rates contained in this tariff.

The components of the Capital Tracker revenue requirement shall include the following:

Revenue requirements for Capital Tracker = (RB x r) + D + OM

Where:

RB = the rate base investment associated with the Capital Tracker. Rate base will consist of all prudently incurred gross plant investment associated with the Capital Tracker, less Accumulated Depreciation associated with the Capital Tracker, less any applicable Accumulated Deferred Income Taxes directly associated with the Capital Tracker.

r = the pretax rate of return approved by the Commission in the Company's most recent rate proceeding, unless otherwise approved by the Commission.

D = the Depreciation Expense, calculated using depreciation rates approved by the Commission in the Company's most recent rate proceeding, and the Commission approved Gross Plant component of A- Rate Base described above.

OM = Incremental O&M expenses associated with the investments recovered through the Capital Tracker.

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SCHEDULE CR

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CAPITAL TRACKER
RIDER - CR

BILLING ADJUSTMENT FACTORS:

The following charges are applied to a customer's monthly energy of each rate schedule as indicated. The amount determined by the application of such unit adjustment shall become a part of the total bill for electric service furnished and will be itemized separately on customer's bill.

DEFINITIONS AND CONDITIONS:

The Company for the purposes of this rate schedule is defined as The Empire District Electric Company.

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THE EMPIRE DISTRICT ELECTRIC COMPANY
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THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 1

THE EMPIRE DISTRICT ELECTRIC COMPANY
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SCHEDULE RG

Replacing Schedule RG Sheet 1

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

RESIDENTIAL GENERAL SERVICE
SCHEDULE RG

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available for residential service to single-family dwellings or to multi-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$	~~14.00~~17.00
For the first 600-Kwh used,	$	0.~~06858~~07920, per Kwh
Additional Kwh,	$	0.~~06112~~07058, per Kwh

WATER HEATING:

When one or more storage-type electric water heaters, with no more than 6,000 watts per heater operating on the line at any time, regularly in operation and is used to supply the Customer's total requirements for hot water, and the Customer so notifies the Company in writing, the Customer Charge will apply each month. For the Kwh each month, the first 600-Kwh of such use will be billed at $0.~~06309~~ 07341 per Kwh, and all in addition to 600-Kwh at the applicable rate as stated above.

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If this schedule is used for service through a single meter to multiple-family dwellings within a single building, each Kwh block will be multiplied by the number of dwelling units served in calculating each month's bill.

Issued December 7 2018
Month Day Year

Effective ~~January 1 2012~~Upon Commission Approval
Month Day Year

By /s/ Jill Schwartz~~Kelly S. Walters~~ ~~President~~ Senior Manager, Rates and Regulatory Affairs
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 1

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE RH

Replacing Schedule RH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

RESIDENTIAL TOTAL ELECTRIC SERVICE
SCHEDULE RH

Sheet 1 of 1 Sheets

AVAILABILITY:

This schedule is available for residential service to Total Electric single-family dwellings or multiple-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$ ~~14.00~~17.00
All Kwh at	$ 0.~~05723~~06626, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If used for service through a single meter to multiple-family dwellings within a single building, the first Kwh-use block and related charge will be multiplied by the number of dwelling units served in calculating each month's bill.
5. Welding, X-ray, or other equipment characterized by severe or fluctuating demands, will not be served.
6. Intermittent or seasonal service will not be provided.
7. Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued December 7 2018
Month Day Year

Effective Upon Commission Approval
Month Day Year

By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued~~
~~Month Day Year~~

~~Effective January 1 2012~~
~~Month Day Year~~

~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** CB
(Name of Issuing Utility)

Replacing Schedule CB Sheet 1

ALL TERRITORY
(Territory to which schedule is applicable) which was filed ~~06-23-10~~01-01-12

COMMERCIAL SERVICE
SCHEDULE CB
Sheet 1 of 1 Sheets

AVAILABILITY:

This schedule is available to any commercial or industrial Customer on the lines of the Company whose electric load is not in excess of 40 Kw, except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$	~~19.00~~20.00
The First 700 Kwh	$	0.~~09284~~09589, per Kwh
For all additional Kwh used	$	0.~~08263~~08534, per Kwh

PAYMENT:

All bills due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.
5. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.
6. The term of service will not be less than one (1) year. Intermittent or seasonal service will not be provided.
7. Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued December 7 2018
Month Day Year
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Month Day Year
By /s/ Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature of Officer Title

~~Issued~~
~~Month Day Year~~
~~Effective January 1 2012~~
~~Month Day Year~~
~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS | Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SH

Replacing Schedule SH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

SMALL HEATING SERVICE
SCHEDULE SH

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available to any general service customer on the lines of the Company whose electric load is not in excess of 40 Kw and where the electric service supplied is the only source of energy at the service location and the customer permanently installs and regularly uses electric space-heating equipment for all internal space-heating comfort requirements. However, this schedule is not available to those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$	~~19.00~~20.00
The First 1000 Kwh used	$	0.~~07891~~08320, per Kwh
Additional Kwh	$	0.~~06963~~07341, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.

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Month Day Year
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Signature Title

~~Issued~~
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~~Month Day Year~~
~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE GP

Replacing Schedule GP Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

GENERAL POWER SERVICE
SCHEDULE GP

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is purely for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

DEMAND CHARGE:

First 40 Kw of Billing Demand .... $ ~~13.02~~13.01, per Kw

Next 460 Kw of Billing Demand .... $ ~~10.39~~10.38, per Kw

All additional Kw of Billing Demand .... $ ~~8.15~~8.14, per Kw

ENERGY CHARGE:

For all Kwh .... $ 0.~~03400~~03397, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:

The Billing Demand will be the highest fifteen minute integrated kilowatt demand registered during the month by a suitable demand meter. In no event shall the Billing Demand be less than 40 Kw.

TRANSFORMER OWNERSHIP:

Where the Customer supplies all facilities (other than metering equipment) for utilization of service at the voltage of the Company's primary line feeding to such location, a discount of 5% will apply to the Demand Charge.

METERING ADJUSTMENT:

The above rate applies for service metered at secondary voltage. Where service is metered at the voltage of the primary line feeding to such location, adjustment for billing will be made by decreasing metered kilowatt hours by 3%.

MINIMUM MONTHLY BILL:

During any month in which service is rendered, the minimum monthly bill will be the Demand Charge.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any

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By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

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~~Month Day Year~~

~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

ALL TERRITORY
(Territory to which schedule is applicable)

Index No. 2

SCHEDULE GP

Replacing Schedule GP Sheet 3

which was filed ~~06-23-10~~01-01-12

GENERAL POWER SERVICE
SCHEDULE GP

other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the

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By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

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~~Month Day Year~~
~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS — Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE PT

Replacing Schedule PT Sheet 4

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

TRANSMISSION SERVICE
SCHEDULE PT

Sheet 1 of 2 Sheets

AVAILABILITY:
This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:
DEMAND CHARGE:

The first 1000-Kw of Billing Demand	$	~~11,858.75~~13,158.00
All additional Kw of Billing Demand	$	~~5.61~~6.22, per Kw

ENERGY CHARGE:

For all Kwh	$	0.~~02083~~02311, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:
The Billing Demand will be determined from the highest fifteen minutes integrated kilowatt demand registered during the month by a suitable demand meter, but no Billing Demand will be less than 65% of the highest such demand established during the year ending with the current month and in no event will the Billing Demand be less than 1000-Kw.

TRANSFORMER OWNERSHIP:
Service will be supplied at the voltage of the Company's primary system serving the area. Where the Company supplies a transformer for the utilization of service at a voltage lower than primary, the transformer will be charged as stated in Rider XC. If service is taken at transmission voltage available at such location, the demand charge will be reduced by 10%.

METERING ADJUSTMENT:
The above rate applies for service metered at primary voltage. Where service is metered at secondary voltage, an adjustment for billing will be made by increasing metered kilowatt hours by 3%. If metered at transmission voltage, metered kilowatt hours and demand will be reduced by 1%. Metering equipment other than standard primary metering will be charged as stated in Rider XC.

MINIMUM MONTHLY BILL:
The minimum bill for any month will be the Demand Charge.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

Issued December 7 2018
Month Day Year
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By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

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~~Month~~ ~~Day~~ ~~Year~~
~~Effective~~ ~~January~~ ~~1~~ ~~2012~~
~~Month~~ ~~Day~~ ~~Year~~
~~By~~ ~~Kelly S. Walters~~ ~~Vice President~~
~~Signature of Officer~~ ~~Title~~

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE TEB

Replacing Schedule TEB Sheet 5

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

TOTAL ELECTRIC BUILDING SERVICE
SCHEDULE TEB

AVAILABILITY:

This schedule is available to any commercial or industrial Customers on the lines of the Company for total electric service except those Customers who are conveying electric service to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, etc., and others who provide transient room and/or room and board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

First 150-Kwh used, or less	$	~~30.46~~32.00
Next 9,850-Kwh used	$	0.~~08460~~08723, per Kwh
All in addition to 10,000-Kwh used	$	0.~~05935~~06120, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.

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	Month	Day	Year
By /s/Jill Schwartz	Senior Manager, Rates and Regulatory Affairs		
Signature			Title

~~Issued~~			
	~~Month~~	~~Day~~	~~Year~~
~~Effective~~	~~January~~	~~1~~	~~2012~~
	~~Month~~	~~Day~~	~~Year~~
~~By~~	~~Kelly S. Walters~~		~~Vice President~~
	~~Signature of Officer~~	~~Title~~	

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available to municipalities served by the Company under the provisions of an Electric Franchise having an original term of not less than ten (10) years, for outdoor lighting for streets, alleys, parks and public places under the provisions of the Company's standard MUNICIPAL ELECTRIC SERVICE AGREEMENT, having an original term of not less than two (2) years.

ANNUAL STREET LIGHTING CHARGE:

The charges below shall apply for street lighting systems (1) owned by the Municipality, or (2) installed, owned, operated and maintained by the Company, in accordance with a Facilities Usage Charge as hereinafter set forth.

Mercury-Vapor Lamp Sizes: (FROZEN)		Watts
7,000 lumen	$ 1~~40.74~~73.05	175
11,000 lumen	$ ~~164.58~~202.36	200
20,000 lumen	$ ~~234.29~~288.07	400
53,000 lumen	$ ~~381.58~~469.17	1000

High-Pressure Sodium-Vapor Lamp Sizes (lucalox, etc.):		
6,000 lumen	$ ~~133.00~~163.53	70
16,000 lumen	$ ~~167.53~~205.99	150
27,500 lumen	$ ~~207.95~~255.68	250
50,000 lumen	$ ~~305.76~~375.95	400
130,000 lumen	$ ~~477.89~~587.59	1000

Light Emitting Diode (LED) Fixtures:		
LED 1 7,500-9,500 lumen	$ 148.05	150
LED 2 13,000-16,000 lumen	$ 189.61	250
LED 3 19,000-22,000 lumen	$ 238.65	400

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA. The Energy Cost Adjustment for street lighting is computed by multiplying monthly burn hours use by the watts per lamp, listed above, times the Energy Cost Adjustment factor.

FACILITIES USAGE (INVESTMENT) CHARGE:

When, by agreement with the Municipality, the Company shall install, own, operate and maintain street lights served under this schedule or is required to provide special or excessive electric facilities to serve Municipality-owned street lighting systems served under this schedule, a separate agreement shall be executed by and between the Municipality and the Company setting forth the investment in such street lighting facilities and a Facilities Usage Charge in the amount of l.5% per month of such investment. The Facilities Usage Charge shall be payable by the Municipality to the Company in the manner prescribed in the aforementioned separate agreement and in addition to the Street Lighting Charge as set forth herein.

DISCOUNT:

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By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued~~
~~Month Day Year~~

~~Effective January 1 2012~~
~~Month Day Year~~

~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

The total charges under this Schedule for Street Lighting and Facilities Usage shall be subject to a fifty percent (50%) discount plus an additional discount which shall be equal to one-half of one percent (0.5%) of the Annual Revenue received by the Company within the Municipality for a period of twelve (12) months ending December 31, from the Customers billed under Rate Schedules for Residential and Commercial service having a Billing Demand (Reserved Capacity) of 40 Kilowatts or less.

MINIMUM:
The total annual net amount of the Street Lighting Charge, plus the Investment Charge, shall not be less than an amount equal to twelve times the total of charges to the Municipality for street lighting service for the calendar month prior to the date of the contract.

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Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

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~~Effective January 1 2012~~
~~Month Day Year~~
~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~6-24-02~~01-04-06

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

PAYMENT:

All bills shall be rendered monthly at 1/12th the annual rates and shall be payable on or before the 25th day of each month succeeding the month during which service was rendered.

CONDITIONS OF SERVICE:

1. No new street lighting installation shall use Incandescent lamps.
2. No new individual lamp installation shall be less than 6,000 lumen.
3. All lamps shall burn every night from dusk to dawn, subject to a reasonable maintenance schedule.
4. The character of street lighting circuit (series or multiple) shall be determined by the Company.
5. If the Municipality owns the Street Lighting System, the Company will furnish electric energy, will inspect street lights, replace broken lamps or glassware (where applicable), and repaint steel poles when necessary. However, replacement or repairs to poles, conduit, cable, overhead conductors or fixtures other than glassware shall be paid for by the Municipality.

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By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

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~~Month Day Year~~

~~By David W. Gibson Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE LS

Replacing Schedule LS Sheet 5

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~06-23-10~~01-01-12

SPECIAL LIGHTING SERVICE
SCHEDULE LS

Sheet 1 of 1 Sheets

AVAILABILITY:
This schedule is available for electric service to sport field lighting, carnival, circus or holiday decorative lighting or similar temporary or seasonal use.

MONTHLY RATE:

For the first 1,000 Kwh used	$	0.~~1308~~16158, per Kwh
For all additional Kwh used	$	0.~~0960~~11859, per Kwh

MINIMUM:
The net monthly minimum charge for any month during which electrical energy is used will be $39.60

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Service will normally be delivered and metered hereunder at the secondary voltage available at the service location. Where physical circumstances would normally make it necessary to meter the service at primary voltage, the Company may at its option install a time clock in place of primary metering facilities to measure the hours-use of the service and compute the kilowatt-hours' consumption of the sport field by using the Customer's connected load. The connected load used for the calculation will be determined at the time of installation and at such subsequent times as the Company may deem necessary by actual load check of the Customer's facilities.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed, or submetered, directly or indirectly.
3. In addition to the above charge, a Customer of temporary nature such as a carnival, circus, etc., will be required to pay the net cost of erection and removal of any special facilities necessary to provide service. Such net cost will include the Company's total expenditure for labor, material, supervision and all other costs necessary to erect and remove facilities for service, less proper credit for actual salvage.
4. Voltage, phase, and frequency of service supplied will be as approved by the Company.
5. Bills for service will be rendered monthly. Where service is for temporary use, the bill for the current month's service will be rendered immediately on discontinuance of service.
6. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued~~
~~Month Day Year~~
~~Effective January 1 2012~~
~~Month Day Year~~
~~By Kelly S. Walters Vice President~~
~~Signature of Officer Title~~

THE STATE CORPORATION COMMISSION OF KANSAS | Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE ~~AERR~~

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~April 14, 2015~~January 6, 2017

~~ASBURY ENVIRONMENTAL AND RIVERTON~~
~~RIDER - AERR~~

Sheet ~~1~~ of ~~2~~ Sheets

RESERVED FOR FUTURE USE

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~~APPLICATION:~~

~~To all bills rendered by the Company for utility service, permitting the recovery of such cost.~~

~~TERM:~~

~~This rider will have a term beginning with the effective date of a Commission Order approving this rider and ending with the rate effective date of the next general rate case, unless extended by the State Corporation Commission of Kansas ("Commission").~~

~~BASIS OF ADJUSTMENT:~~

~~Company will collect from customers as an adjustment to the aforementioned bills, an additional charge equal to the annual capital investment-related revenue requirements associated with the Asbury Environmental Retrofit and Riverton 12 Project (AERR) undertaken by Company. The calculation of such revenue requirements will be made in conformity with the formula stated in this Rider, and will not change absent Commission approval.~~

Commission File Number

Issued December 7 2018
Month Day Year

Effective Upon Commission Approval
Month Day Year

By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued January 06 2017~~
~~Month Day Year~~

~~Effective July 01 2017~~
~~Month Day Year~~

~~By /s/ Chris Krygier Director, Rates and Regulatory Affairs~~
~~Signature Title~~

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** ~~AERR~~
(Name of Issuing Utility)

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable) which was filed ~~April 14, 2015~~January 6, 2017

~~ASBURY ENVIRONMENTAL AND RIVERTON~~
~~RIDER - AERR~~

Sheet ~~1~~ of ~~2~~ Sheets

~~Company shall provide periodic reports to the Commission of its collections including a calculation of the total collected under this Rider.~~

~~METHOD OF BILLING:~~
~~The additional charge shall be collected by applying the following factor and adding the charge to each applicable customer's bill. The billing method shall include:~~

~~1. A per kilowatt hour (kWh) charge determined by dividing the AERR revenue requirements by the annual applicable kWh sales.~~

~~BASIS FOR DETERMINING THE AERR:~~
~~The monthly charge shall reflect the recovery of the AERR revenue requirement as approved by the Commission. The AERR charge shall be implemented on an interim basis subject to refund, and shall remain fixed until otherwise ordered by the Commission.~~

~~ANNUAL TRUE-UP:~~
~~The revenue collected pursuant to the application of this Rider shall be compared to the estimated revenue approved for collection by the Commission on an annualized basis. The amount of any over (under) recovery shall be included in any refund calculation that may result from the re-calculation of the revenue requirement to take place during Empire's next rate case.~~

~~INTERIM SUBJECT TO REFUND:~~
~~The revenue collected pursuant to this rider, as approved by the Commission, shall be collected on an interim basis, subject to refund. For purposes of determining whether a refund is necessary, each component of the AERR revenue requirement will be determined by the Commission during Empire's next general rate case. The AERR revenue requirement will then be compared against the AERR revenue requirement approved by the Commission. If the AERR revenue requirement calculated by the Commission in Empire's next general rate case is less than the AERR revenue requirement approved by the Commission, then Empire shall refund the difference through a bill credit. The refund rates (bill credits) shall be distributed to customers in the same fashion as the original AERR rates~~

Commission File Number

Issued	December	7	2018
	Month	Day	Year
Effective	Upon Commission Approval		
	Month	Day	Year

By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued~~	~~January~~	~~06~~	~~2017~~
	~~Month~~	~~Day~~	~~Year~~
~~Effective~~	~~July~~	~~01~~	~~2017~~
	~~Month~~	~~Day~~	~~Year~~

~~By /s/ Chris Krygier Director, Rates and Regulatory Affairs~~
~~Signature Title~~

THE STATE CORPORATION COMMISSION OF KANSAS — Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE ~~AERR~~

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~April 14, 2015~~January 6, 2017

ASBURY ENVIRONMENTAL COST RECOVERY
RIDER - AERR

Sheet ~~2~~ of ~~2~~ Sheets

~~contained in this tariff. The components of the AERR revenue requirement to be determined in the next general rate case shall include the following:~~

~~Revenue requirements for AERR = (RB x r) + D~~

~~RB = the rate base investment associated with the AERR. Rate base will consist of all prudently incurred gross plant investment associated with the AERR, less Accumulated Depreciation associated with the AERR, less any applicable Accumulated Deferred Income Taxes directly associated with the AERR.~~

~~r = the pretax rate of return approved by the Commission in Docket No. 16-EPDE-410-ACQ, unless otherwise agreed to by the parties and the Commission.~~

~~D = the Depreciation Expense, calculated using Commission approved depreciation rates, and the Commission approved Gross Plant component of A- Rate Base described above.~~

~~BILLING ADJUSTMENT FACTORS:~~
~~The following charges are applied to a customer's monthly energy of each rate schedule as indicated. The amount determined by the application of such unit adjustment shall become a part of the total bill for electric service furnished and will be itemized separately on customer's bill.~~

~~Rate Schedule~~	~~$ per kWh~~
~~Residential Service – Schedule RG~~	~~$0.00798~~
~~Residential Total Electric Service – Schedule RH~~	~~$0.00798~~
~~Commercial Service – Schedule CB~~	~~$0.00798~~
~~Small Heating Service – Schedule SH~~	~~$0.00798~~
~~General Power Service – Schedule GP~~	~~$0.00798~~
~~Transmission Service – Schedule PT~~	~~$0.00798~~
~~Total Electric Building Service – Schedule TEB~~	~~$0.00798~~
~~Mobile Home Park Service – Schedule MHP~~	~~$0.00798~~
~~Municipal Street Lighting Service – Schedule SPL~~	~~$0.00798~~
~~Private Lighting Service – Schedule PL~~	~~$0.00798~~
~~Special Lighting Service – Schedule LS~~	~~$0.00798~~
~~Miscellaneous Service – Schedule MS~~	~~$0.00798~~

Commission File Number

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued January 06 2017~~
~~Month Day Year~~
~~Effective July 01 2017~~
~~Month Day Year~~
~~By /s/ Chris Krygier Director, Rates and Regulatory Affairs~~
~~Signature Title~~

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THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE AERR

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed ~~April 14, 2015~~January 6, 2017

ASBURY ENVIRONMENTAL COST RECOVERY
RIDER - AERR

Sheet 2 of 2 Sheets

~~Church and School Service – Rider SC~~	~~$0.00798~~
~~General Municipal Service – Rider M~~	~~$0.00798~~

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~~DEFINITIONS AND CONDITIONS:~~
~~Company for the purposes of this rate schedule or rider is defined as The Empire District Electric Company.~~

Commission File Number

Issued December 7 2018
Month Day Year
Effective Upon Commission Approval
Month Day Year
By /s/Jill Schwartz Senior Manager, Rates and Regulatory Affairs
Signature Title

~~Issued January 06 2017~~
~~Month Day Year~~
~~Effective July 01 2017~~
~~Month Day Year~~
~~By /s/ Chris Krygier Director, Rates and Regulatory Affairs~~
~~Signature Title~~

Index No. A

THE EMPIRE DISTRICT ELECTRIC COMPANY (Name of Issuing Utility)	SCHEDULE:	Table of Contents	
ALL TERRITORY (Territory to which schedule is applicable)	Replacing Schedule which was filed	Table of Contents 12-21-11	Sheet 1

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Issued	February Month	23 Day	2015 Year
Effective	Month	Day	Year
By	Signature of Officer		Vice President Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 1

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE RG

Replacing Schedule RG Sheet 1

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

RESIDENTIAL GENERAL SERVICE
SCHEDULE RG

AVAILABILITY:

This schedule is available for residential service to single-family dwellings or to multi-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$	14.00
For the first 600-Kwh used,	$	0.06858, per Kwh
Additional Kwh,	$	0.06112, per Kwh

WATER HEATING:

When one or more storage-type electric water heaters, with no more than 6,000 watts per heater operating on the line at any time, regularly in operation and is used to supply the Customer's total requirements for hot water, and the Customer so notifies the Company in writing, the Customer Charge will apply each month. For the Kwh each month, the first 600-Kwh of such use will be billed at $0.06309 per Kwh, and all in addition to 600-Kwh at the applicable rate as stated above.

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If this schedule is used for service through a single meter to multiple-family dwellings within a single building, each Kwh block will be multiplied by the number of dwelling units served in calculating each month's bill.

Issued
Month Day Year

Effective January 1 2012
Month Day Year

By Kelly S. Walters Vice President
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 1

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE RH

Replacing Schedule RH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

RESIDENTIAL TOTAL ELECTRIC SERVICE
SCHEDULE RH

AVAILABILITY:
This schedule is available for residential service to Total Electric single-family dwellings or multiple-family dwellings within a single building. This schedule is not available for service through a single meter to two or more separate buildings each containing one or more dwelling units.

MONTHLY RATE:

Customer Charge, plus	$ 14.00
All Kwh at	$ 0.05723, per Kwh

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Payment must be rendered so that credit can be posted to the account prior to preparation of the next normal billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. If used for service through a single meter to multiple-family dwellings within a single building, the first Kwh-use block and related charge will be multiplied by the number of dwelling units served in calculating each month's bill.
5. Welding, X-ray, or other equipment characterized by severe or fluctuating demands, will not be served.
6. Intermittent or seasonal service will not be provided.
7. Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued			
	Month	Day	Year
Effective	January	1	2012
	Month	Day	Year
By	Kelly S. Walters		Vice President
	Signature of Officer		Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE CB

Replacing Schedule CB Sheet 1

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

COMMERCIAL SERVICE
SCHEDULE CB

Sheet 1 of 1 Sheets

AVAILABILITY:

This schedule is available to any commercial or industrial Customer on the lines of the Company whose electric load is not in excess of 40 Kw, except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$	19.00
The First 700 Kwh	$	0.09284, per Kwh
For all additional Kwh used	$	0.08263, per Kwh

PAYMENT:

All bills due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.
5. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.
6. The term of service will not be less than one (1) year. Intermittent or seasonal service will not be provided.
7 Bills for service will be rendered monthly. At the option of the Company, however, the meters may be read bimonthly with the bill for the alternate month based upon an estimated Kwh consumption.
8. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued			
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By	Kelly S. Walters		Vice President
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THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SH

Replacing Schedule SH Sheet 2

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

SMALL HEATING SERVICE
SCHEDULE SH

Sheet 1 of 2 Sheets

AVAILABILITY:

This schedule is available to any general service customer on the lines of the Company whose electric load is not in excess of 40 Kw and where the electric service supplied is the only source of energy at the service location and the customer permanently installs and regularly uses electric space-heating equipment for all internal space-heating comfort requirements. However, this schedule is not available to those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and/or board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

Customer Charge, plus	$	19.00
The First 1000 Kwh used	$	0.07891, per Kwh
Additional Kwh	$	0.06963, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Where the Customer's use of welding, or other equipment characterized by fluctuating or severe demands, necessitates the installation of additional or increased facilities (including distribution transformers, service conductors or secondaries) solely to serve such Customer, the applicable provisions of Rider XC will apply in amendment to the provisions of this schedule.

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By	Kelly S. Walters		Vice President
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THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE GP

Replacing Schedule GP Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

GENERAL POWER SERVICE
SCHEDULE GP

AVAILABILITY:

This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is purely for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

DEMAND CHARGE:

First 40 Kw of Billing Demand	$	13.02, per Kw
Next 460 Kw of Billing Demand	$	10.39, per Kw
All additional Kw of Billing Demand	$	8.15, per Kw

ENERGY CHARGE:

For all Kwh	$	0.03400, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:

The Billing Demand will be the highest fifteen minute integrated kilowatt demand registered during the month by a suitable demand meter. In no event shall the Billing Demand be less than 40 Kw.

TRANSFORMER OWNERSHIP:

Where the Customer supplies all facilities (other than metering equipment) for utilization of service at the voltage of the Company's primary line feeding to such location, a discount of 5% will apply to the Demand Charge.

METERING ADJUSTMENT:

The above rate applies for service metered at secondary voltage. Where service is metered at the voltage of the primary line feeding to such location, adjustment for billing will be made by decreasing metered kilowatt hours by 3%.

MINIMUM MONTHLY BILL:

During any month in which service is rendered, the minimum monthly bill will be the Demand Charge.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the

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By	Kelly S. Walters		Vice President
	Signature of Officer		Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** PT
(Name of Issuing Utility)

Replacing Schedule PT Sheet 4

ALL TERRITORY
(Territory to which schedule is applicable) which was filed 06-23-10

TRANSMISSION SERVICE
SCHEDULE PT

AVAILABILITY:

This schedule is available for electric service to any commercial or industrial Customer except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient rooms and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

DEMAND CHARGE:

The first 1000-Kw of Billing Demand	$	11,858.75
All additional Kw of Billing Demand	$	5.61, per Kw

ENERGY CHARGE:

For all Kwh	$	0.02083, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

DETERMINATION OF BILLING DEMAND:

The Billing Demand will be determined from the highest fifteen minutes integrated kilowatt demand registered during the month by a suitable demand meter, but no Billing Demand will be less than 65% of the highest such demand established during the year ending with the current month and in no event will the Billing Demand be less than 1000-Kw.

TRANSFORMER OWNERSHIP:

Service will be supplied at the voltage of the Company's primary system serving the area. Where the Company supplies a transformer for the utilization of service at a voltage lower than primary, the transformer will be charged as stated in Rider XC. If service is taken at transmission voltage available at such location, the demand charge will be reduced by 10%.

METERING ADJUSTMENT:

The above rate applies for service metered at primary voltage. Where service is metered at secondary voltage, an adjustment for billing will be made by increasing metered kilowatt hours by 3%. If metered at transmission voltage, metered kilowatt hours and demand will be reduced by 1%. Metering equipment other than standard primary metering will be charged as stated in Rider XC.

MINIMUM MONTHLY BILL:

The minimum bill for any month will be the Demand Charge.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

Issued ____________________
Month Day Year

Effective January 1 2012
Month Day Year

By Kelly S. Walters Vice President
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 2

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE TEB

Replacing Schedule TEB Sheet 5

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

TOTAL ELECTRIC BUILDING SERVICE
SCHEDULE TEB

AVAILABILITY:

This schedule is available to any commercial or industrial Customers on the lines of the Company for total electric service except those Customers who are conveying electric service to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, etc., and others who provide transient room and/or room and board service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

MONTHLY RATE:

First 150-Kwh used, or less	$	30.46
Next 9,850-Kwh used	$	0.08460, per Kwh
All in addition to 10,000-Kwh used	$	0.05935, per Kwh

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:

All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:

There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:

1. The voltage, phase and frequency of energy supplied will be as approved by the Company.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed or submetered, directly or indirectly.
3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.
4. Living quarters incidental to commercial or industrial operations in the same building will only be served together with these operations through a single meter and billed under this or other applicable commercial industrial rates. Living quarters detached from commercial or industrial buildings will only be served under applicable residential schedules.

Issued			
	Month	Day	Year
Effective	January	1	2012
	Month	Day	Year
By	Kelly S. Walters		Vice President
	Signature of Officer		Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 06-23-10

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

AVAILABILITY:

This schedule is available to municipalities served by the Company under the provisions of an Electric Franchise having an original term of not less than ten (10) years, for outdoor lighting for streets, alleys, parks and public places under the provisions of the Company's standard MUNICIPAL ELECTRIC SERVICE AGREEMENT, having an original term of not less than two (2) years.

ANNUAL STREET LIGHTING CHARGE:

The charges below shall apply for street lighting systems (1) owned by the Municipality, or (2) installed, owned, operated and maintained by the Company, in accordance with a Facilities Usage Charge as hereinafter set forth.

		Watts
Mercury-Vapor Lamp Sizes:		
7,000 lumen	$ 140.74	175
11,000 lumen	$ 164.58	200
20,000 lumen	$ 234.29	400
53,000 lumen	$ 381.58	1000
High-Pressure Sodium-Vapor Lamp Sizes (lucalox, etc.):		
6,000 lumen	$ 133.00	70
16,000 lumen	$ 167.53	150
27,500 lumen	$ 207.95	250
50,000 lumen	$ 305.76	400
130,000 lumen	$ 477.89	1000

ENERGY COST ADJUSTMENT:

The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA. The Energy Cost Adjustment for street lighting is computed by multiplying monthly burn hours use by the watts per lamp, listed above, times the Energy Cost Adjustment factor.

FACILITIES USAGE (INVESTMENT) CHARGE:

When, by agreement with the Municipality, the Company shall install, own, operate and maintain street lights served under this schedule or is required to provide special or excessive electric facilities to serve Municipality-owned street lighting systems served under this schedule, a separate agreement shall be executed by and between the Municipality and the Company setting forth the investment in such street lighting facilities and a Facilities Usage Charge in the amount of l.5% per month of such investment. The Facilities Usage Charge shall be payable by the Municipality to the Company in the manner prescribed in the aforementioned separate agreement and in addition to the Street Lighting Charge as set forth herein.

DISCOUNT:

The total charges under this Schedule for Street Lighting and Facilities Usage shall be subject to a fifty percent (50%) discount plus an additional discount which shall be equal to one-half of one percent (0.5%) of the Annual Revenue received by the Company within the Municipality for a period of twelve (12) months ending December 31, from the Customers billed under Rate Schedules for Residential and Commercial service having a Billing Demand (Reserved Capacity) of 40 Kilowatts or less.

MINIMUM:

The total annual net amount of the Street Lighting Charge, plus the Investment Charge, shall not be less than an amount equal to twelve times the total of charges to the Municipality for street lighting service for the calendar month prior to the date of the contract.

Issued			
	Month	Day	Year
Effective	January	1	2012
	Month	Day	Year
By	Kelly S. Walters		Vice President
	Signature of Officer		Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE SPL

Replacing Schedule SPL Sheet 3

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed 6-24-02

MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE SPL

PAYMENT:

All bills shall be rendered monthly at 1/12th the annual rates and shall be payable on or before the 25th day of each month succeeding the month during which service was rendered.

CONDITIONS OF SERVICE:

1. No new street lighting installation shall use Incandescent lamps.
2. No new individual lamp installation shall be less than 6,000 lumen.
3. All lamps shall burn every night from dusk to dawn, subject to a reasonable maintenance schedule.
4. The character of street lighting circuit (series or multiple) shall be determined by the Company.
5. If the Municipality owns the Street Lighting System, the Company will furnish electric energy, will inspect street lights, replace broken lamps or glassware, and repaint steel poles when necessary. However, replacement or repairs to poles, conduit, cable, overhead conductors or fixtures other than glassware shall be paid for by the Municipality.

Issued			
	Month	Day	Year
Effective	January	4	2006
	Month	Day	Year
By	David W. Gibson		Vice President
	Signature of Officer		Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 3

THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** LS
(Name of Issuing Utility)

Replacing Schedule LS Sheet 5

ALL TERRITORY
(Territory to which schedule is applicable) which was filed 06-23-10

SPECIAL LIGHTING SERVICE
SCHEDULE LS

Sheet 1 of 1 Sheets

AVAILABILITY:
This schedule is available for electric service to sport field lighting, carnival, circus or holiday decorative lighting or similar temporary or seasonal use.

MONTHLY RATE:

For the first 1,000 Kwh used	$	0.1308, per Kwh
For all additional Kwh used	$	0.0960, per Kwh

MINIMUM:
The net monthly minimum charge for any month during which electrical energy is used will be $39.60

ENERGY COST ADJUSTMENT:
The above charges will be adjusted in an amount provided by the terms and provisions of the Energy Cost Adjustment, Rider ECA.

PAYMENT:
All bills are due and payable upon receipt. A bill is deemed delinquent if not paid by the date stated on the bill. Bills are delinquent after the fifteenth (15th) day after the date of billing. A late payment charge of two percent (2%) will be assessed on the delinquent amount owed for current utility service.

GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES:
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

CONDITIONS OF SERVICE:
1. Service will normally be delivered and metered hereunder at the secondary voltage available at the service location. Where physical circumstances would normally make it necessary to meter the service at primary voltage, the Company may at its option install a time clock in place of primary metering facilities to measure the hours-use of the service and compute the kilowatt-hours' consumption of the sport field by using the Customer's connected load. The connected load used for the calculation will be determined at the time of installation and at such subsequent times as the Company may deem necessary by actual load check of the Customer's facilities.
2. Service will be furnished for the sole use of the Customer and will not be resold, redistributed, or submetered, directly or indirectly.
3. In addition to the above charge, a Customer of temporary nature such as a carnival, circus, etc., will be required to pay the net cost of erection and removal of any special facilities necessary to provide service. Such net cost will include the Company's total expenditure for labor, material, supervision and all other costs necessary to erect and remove facilities for service, less proper credit for actual salvage.
4. Voltage, phase, and frequency of service supplied will be as approved by the Company.
5. Bills for service will be rendered monthly. Where service is for temporary use, the bill for the current month's service will be rendered immediately on discontinuance of service.
6. The Company Rules and Regulations, K.C.C. No. 4, Index 6, are a part of this schedule.

Issued
Month Day Year
Effective January 1 2012
Month Day Year
By Kelly S. Walters Vice President
Signature of Officer Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Name of Issuing Utility)

SCHEDULE AERR

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable)

which was filed April 14, 2015

ASBURY ENVIRONMENTAL AND RIVERTON
RIDER - AERR

Sheet 1 of 2 Sheets

APPLICATION:
To all bills rendered by the Company for utility service, permitting the recovery of such cost.

TERM:
This rider will have a term beginning with the effective date of a Commission Order approving this rider and ending with the rate effective date of the next general rate case, unless extended by the State Corporation Commission of Kansas ("Commission").

BASIS OF ADJUSTMENT:
Company will collect from customers as an adjustment to the aforementioned bills, an additional charge equal to the annual capital investment-related revenue requirements associated with the Asbury Environmental Retrofit and Riverton 12 Project (AERR) undertaken by Company. The calculation of such revenue requirements will be made in conformity with the formula stated in this Rider, and will not change absent Commission approval.

Company shall provide periodic reports to the Commission of its collections including a calculation of the total collected under this Rider.

METHOD OF BILLING:
The additional charge shall be collected by applying the following factor and adding the charge to each applicable customer's bill. The billing method shall include:

1. A per kilowatt hour (kWh) charge determined by dividing the AERR revenue requirements by the annual applicable kWh sales.

BASIS FOR DETERMINING THE AERR:
The monthly charge shall reflect the recovery of the AERR revenue requirement as approved by the Commission. The AERR charge shall be implemented on an interim basis subject to refund, and shall remain fixed until otherwise ordered by the Commission.

ANNUAL TRUE-UP:
The revenue collected pursuant to the application of this Rider shall be compared to the estimated revenue approved for collection by the Commission on an annualized basis. The amount of any over (under) recovery shall be included in any refund calculation that may result from the re-calculation of the revenue requirement to take place during Empire's next rate case.

INTERIM SUBJECT TO REFUND:
The revenue collected pursuant to this rider, as approved by the Commission, shall be collected on an interim basis, subject to refund. For purposes of determining whether a refund is necessary, each component of the AERR revenue requirement will be determined by the Commission during Empire's next general rate case. The AERR revenue requirement will then be compared against the AERR revenue requirement approved by the Commission. If the AERR revenue requirement calculated by the Commission in Empire's next general rate case is less than the AERR revenue requirement approved by the Commission, then Empire shall refund the difference through a bill credit. The refund rates (bill credits) shall be distributed to customers in the same fashion as the original AERR rates

Commission File Number

Issued	January	06	2017
	Month	Day	Year
Effective	July	01	2017
	Month	Day	Year

By /s/ Chris Krygier Director, Rates and Regulatory Affairs
Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS Index No. 4

THE EMPIRE DISTRICT ELECTRIC COMPANY **SCHEDULE** AERR
(Name of Issuing Utility)

Replacing Schedule AECR Sheet 12

ALL TERRITORY
(Territory to which schedule is applicable) which was filed April 14, 2015

ASBURY ENVIRONMENTAL COST RECOVERY
RIDER - AERR

contained in this tariff. The components of the AERR revenue requirement to be determined in the next general rate case shall include the following:

Revenue requirements for AERR = (RB x r) + D

RB = the rate base investment associated with the AERR. Rate base will consist of all prudently incurred gross plant investment associated with the AERR, less Accumulated Depreciation associated with the AERR, less any applicable Accumulated Deferred Income Taxes directly associated with the AERR.

r = the pretax rate of return approved by the Commission in Docket No. 16-EPDE-410-ACQ, unless otherwise agreed to by the parties and the Commission.

D = the Depreciation Expense, calculated using Commission approved depreciation rates, and the Commission approved Gross Plant component of A- Rate Base described above.

BILLING ADJUSTMENT FACTORS:

The following charges are applied to a customer's monthly energy of each rate schedule as indicated. The amount determined by the application of such unit adjustment shall become a part of the total bill for electric service furnished and will be itemized separately on customer's bill.

Rate Schedule	$ per kWh
Residential Service – Schedule RG	$0.00798
Residential Total Electric Service – Schedule RH	$0.00798
Commercial Service – Schedule CB	$0.00798
Small Heating Service – Schedule SH	$0.00798
General Power Service – Schedule GP	$0.00798
Transmission Service – Schedule PT	$0.00798
Total Electric Building Service – Schedule TEB	$0.00798
Mobile Home Park Service – Schedule MHP	$0.00798
Municipal Street Lighting Service – Schedule SPL	$0.00798
Private Lighting Service – Schedule PL	$0.00798
Special Lighting Service – Schedule LS	$0.00798
Miscellaneous Service – Schedule MS	$0.00798
Church and School Service – Rider SC	$0.00798
General Municipal Service – Rider M	$0.00798

DEFINITIONS AND CONDITIONS:

Company for the purposes of this rate schedule or rider is defined as The Empire District Electric Company.

Commission File Number __________

Issued	January	06	2017
	Month	Day	Year
Effective	July	01	2017
	Month	Day	Year

By /s/ Chris Krygier Director, Rates and Regulatory Affairs
Signature Title