OHIO POWER COMPANY AND SUBSIDIARIES

OHIO POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	3,834	4,123
Commercial	3,516	3,527
Industrial	3,543	3,623
Miscellaneous	30	31
Total Retail (a)	10,923	11,304
Wholesale (b)	390	638
Total KWhs	11,313	11,942

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio's contractually obligated purchases of OVEC power sold to PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2020	2019
	(in degree days)	
Actual – Heating (a)	1,473	1,892
Normal – Heating (b)	1,898	1,877
Actual – Cooling (c)	3	1
Normal – Cooling (b)	3	3

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Net Income
(in millions)

First Quarter of 2019	$	128.0
Changes in Gross Margin:		
Retail Margins		(93.7)
Margins from Off-system Sales		2.3
Transmission Revenues		0.6
Other Revenues		5.5
Total Change in Gross Margin		(85.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		40.5
Depreciation and Amortization		(7.2)
Taxes Other Than Income Taxes		(3.1)
Interest Income		(0.6)
Carrying Costs Income		0.2
Allowance for Equity Funds Used During Construction		(3.3)
Non-Service Cost Components of Net Periodic Benefit Cost		0.1
Interest Expense		(4.3)
Total Change in Expenses and Other		22.3
Income Tax Expense		10.1
First Quarter of 2020	$	75.1

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** decreased $94 million primarily due to the following:
  - A $58 million decrease due to a reversal of a regulatory provision in the first quarter of 2019.
  - A $39 million net decrease in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $13 million decrease in Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - A $7 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $5 million decrease due to the OVEC PPA rider which was replaced by the Legacy Generation Resource Rider (LGRR). This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $3 million decrease in revenues associated with a vegetation management rider. This decrease was offset in Other Operation and Maintenance expenses below.

  These decreases were partially offset by:
  - A $17 million increase in rider revenues associated with the DIR. This increase was partially offset in other expense items below.
  - A $7 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - A $7 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset in Other Operation and Maintenance expenses below.
  - A $3 million increase in Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.
- **Other Revenues** increased $6 million primarily due to third-party LGRR revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins above.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $41 million primarily due to the following:
  - A $40 million decrease in recoverable PJM expenses. This decrease was offset in Gross Margin above.
  - A $6 million decrease in PJM expenses primarily related to the annual formula rate true-up.
  - A $4 million decrease in recoverable distribution expenses related to vegetation management. This decrease was partially offset in Retail Margins above.

  These decreases were partially offset by:
  - A $7 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $7 million primarily due to the following:
  - A $5 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $5 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019.
  - A $5 million increase in recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
  - A $10 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $3 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** decreased $3 million primarily due to adjustments that resulted from 2019 FERC audit findings and decreased projects.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $10 million due to a decrease in pretax book income partially offset by a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset in Retail Margins above.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31, 2020	2019
REVENUES		
Electricity, Transmission and Distribution	$ 679.2	$ 826.5
Sales to AEP Affiliates	8.4	7.5
Other Revenues	2.7	2.8
TOTAL REVENUES	690.3	836.8
EXPENSES		
Purchased Electricity for Resale	149.1	174.2
Purchased Electricity from AEP Affiliates	42.4	46 1
Amortization of Generation Deferrals	—	32.4
Other Operation	177.3	216 9
Maintenance	31.6	32.5
Depreciation and Amortization	70.5	63.3
Taxes Other Than Income Taxes	112.0	108.9
TOTAL EXPENSES	582.9	674.3
OPERATING INCOME	107.4	162 5
Other Income (Expense):		
Interest Income	0.2	0.8
Carrying Costs Income	0.4	0.2
Allowance for Equity Funds Used During Construction	1.9	5.2
Non-Service Cost Components of Net Periodic Benefit Cost	3 8	3 7
Interest Expense	(28.9)	(24.6)
INCOME BEFORE INCOME TAX EXPENSE	84.8	147.8
Income Tax Expense	9.7	19.8
NET INCOME	$ 75.1	$ 128.0

The common stock of OPCo is wholly-owned by Parent

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
Net Income	$ 75.1	$ 128.0
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $(0.1) in 2020 and 2019, Respectively	—	(0.3)
TOTAL COMPREHENSIVE INCOME	$ 75.1	$ 127.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 321.2	$ 838.8	$ 1,136.4	$ 1.0	$ 2,297.4
Common Stock Dividends			(25.0)		(25.0)
Net Income			128.0		128.0
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	$ 321.2	$ 838 8	$ 1,239.4	$ 0.7	$ 2,400 1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 321.2	$ 838.8	$ 1,348.5	$ —	$ 2,508 5
Common Stock Dividends			(21.9)		(21.9)
ASU 2016-13 Adoption			0.3		0.3
Net Income			75.1		75.1
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	$ 321.2	$ 838.8	$ 1,402.0	$ —	$ 2,562.0

See Condensed Notes to Condensed Fmancial Statements of Regıstrants begınnıng on page 110.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2020 and December 31, 2019
(in millions)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.1	$ 3.7
Accounts Receivable·		
Customers	42.9	53.0
Affiliated Companies	73 1	59.3
Accrued Unbilled Revenues	34.2	20.3
Miscellaneous	3.8	0.5
Allowance for Uncollectible Accounts	(0.4)	(0.7)
Total Accounts Receivable	153.6	132.4
Materials and Supplies	58.3	52.3
Renewable Energy Credits	26 9	30 9
Prepayments and Other Current Assets	23.7	19.2
TOTAL CURRENT ASSETS	265 6	238 5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,713.0	2,686.3
Distribution	5,404.5	5,323.5
Other Property, Plant and Equipment	797.2	765.8
Construction Work in Progress	412.5	394.4
Total Property, Plant and Equipment	9,327 2	9,170.0
Accumulated Depreciation and Amortization	2,292.8	2,263.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,034.4	6,907.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	396.4	351.8
Deferred Charges and Other Noncurrent Assets	485 6	546.3
TOTAL OTHER NONCURRENT ASSETS	882.0	898.1
TOTAL ASSETS	$ 8,182.0	$ 8,043.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

**OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2020 and December 31, 2019
(dollars in millions)
(Unaudited)**

	March 31, 2020	December 31, 2019
CURRENT LIABILITIES		
Advances from Affiliates	$ 29.4	$ 131.0
Accounts Payable:		
General	220.3	233.7
Affiliated Companies	109.0	103.6
Long-term Debt Due Within One Year – Nonaffiliated	0.1	0.1
Risk Management Liabilities	8.7	7.3
Customer Deposits	74.1	70.6
Accrued Taxes	449 2	587.9
Obligations Under Operating Leases	13.0	12.5
Other Current Liabilities	139.5	151.2
TOTAL CURRENT LIABILITIES	1,043.3	1,297.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,429.0	2,081.9
Long-term Risk Management Liabilities	112.2	96.3
Deferred Income Taxes	871.0	849 4
Regulatory Liabilities and Deferred Investment Tax Credits	1,040.6	1,090.9
Obligations Under Operating Leases	79.8	76.0
Deferred Credits and Other Noncurrent Liabilities	44.1	42.7
TOTAL NONCURRENT LIABILITIES	4,576.7	4,237.2
TOTAL LIABILITIES	5,620.0	5,535 1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value.		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838 8	838.8
Retained Earnings	1,402.0	1,348 5
TOTAL COMMON SHAREHOLDER'S EQUITY	2,562.0	2,508.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 8,182.0	$ 8,043.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	2019
OPERATING ACTIVITIES		
Net Income	$ 75.1	$ 128 0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	70.5	63 3
Amortization of Generation Deferrals	—	32 4
Deferred Income Taxes	12.9	10.1
Allowance for Equity Funds Used During Construction	(1 9)	(5 2)
Mark-to-Market of Risk Management Contracts	17.3	6.7
Property Taxes	74 4	66 0
Refund of Global Settlement	—	(4.1)
Reversal of Regulatory Provision	—	(56 2)
Change in Other Noncurrent Assets	(61.5)	(7 5)
Change in Other Noncurrent Liabilities	(36 4)	17 6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(19 9)	31 7
Materials and Supplies	(10.2)	(3.4)
Accounts Payable	35 5	(23 9)
Accrued Taxes, Net	(141.9)	(114.4)
Other Current Assets	(2 0)	(7 7)
Other Current Liabilities	(8.4)	(16 2)
Net Cash Flows from Operating Activities	3 5	117 2
INVESTING ACTIVITIES		
Construction Expenditures	(232.8)	(198 5)
Other Investing Activities	5 9	3 7
Net Cash Flows Used for Investing Activities	(226.9)	(194.8)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	347 1	—
Change in Advances from Affiliates, Net	(101.6)	113.5
Retirement of Long-term Debt – Nonaffiliated	—	(23.4)
Principal Payments for Finance Lease Obligations	(1.2)	(0.7)
Dividends Paid on Common Stock	(21.9)	(25 0)
Other Financing Activities	0.4	0.5
Net Cash Flows from Financing Activities	222 8	64 9
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(0 6)	(12 7)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	3.7	32.5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 3 1	$ 19 8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 16.7	$ 17.0
Net Cash Paid (Received) for Income Taxes	—	(0 2)
Noncash Acquisitions Under Finance Leases	4.3	3.2
Construction Expenditures Included in Current Liabilities as of March 31,	72 9	72 8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

PUBLIC SERVICE COMPANY OF OKLAHOMA

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	1,362	1,520
Commercial	1,055	1,089
Industrial	1,437	1,433
Miscellaneous	272	274
Total Retail	4,126	4,316
Wholesale	53	245
Total KWhs	4,179	4,561

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2020	2019
	(in degree days)	
Actual – Heating (a)	799	1,171
Normal – Heating (b)	1,034	1,032
Actual – Cooling (c)	33	3
Normal – Cooling (b)	17	17

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Net Income (Loss)
(in millions)

First Quarter of 2019	$	6.2
Changes in Gross Margin:		
Retail Margins (a)		—
Margins from Off-system Sales		(0.2)
Transmission Revenues		(0.5)
Other Revenues		(1.2)
Total Change in Gross Margin		(1.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		(15.5)
Depreciation and Amortization		(1.2)
Taxes Other Than Income Taxes		0.1
Interest Income		0.1
Allowance for Equity Funds Used During Construction		0.9
Interest Expense		1.1
Total Change in Expenses and Other		(14.5)
Income Tax Expense		(0.1)
First Quarter of 2020	$	(10.3)

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** were consistent with the prior year due to the following:
  - An $11 million increase due to new base rates implemented in April 2019.

  This increase was partially offset by:
  - A $7 million decrease in revenue from rate riders. This decrease was partially offset in other expense items below.
  - A $3 million decrease in weather-related usage due to a 32% decrease in heating degree days.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $16 million primarily due the following:
  - A $6 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $5 million increase in distribution expenses primarily due to an increase in vegetation management expenses.
  - A $1 million increase in Energy Efficiency program costs. This increase was offset in Retail Margins above.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
REVENUES		
Electric Generation, Transmission and Distribution	$ 295.4	$ 329.2
Sales to AEP Affiliates	1.1	1.6
Other Revenues	0.8	2.0
TOTAL REVENUES	297.3	332.8
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	16.9	38.0
Purchased Electricity for Resale	110.4	122.9
Other Operation	87.2	73.6
Maintenance	24.4	22.5
Depreciation and Amortization	44.7	43.5
Taxes Other Than Income Taxes	11.3	11.4
TOTAL EXPENSES	294.9	311.9
OPERATING INCOME	2.4	20.9
Other Income (Expense):		
Interest Income	0 1	—
Allowance for Equity Funds Used During Construction	1.0	0.1
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1
Interest Expense	(15.8)	(16.9)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE	(10.2)	6.2
Income Tax Expense	0.1	—
NET INCOME (LOSS)	$ (10.3)	$ 6.2

The common stock of PSO is wholly-owned by Parent

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
Net Income (Loss)	$ (10.3)	$ 6.2
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2020 and 2019, Respectively	(0.2)	(0.2)
TOTAL COMPREHENSIVE INCOME (LOSS)	$ (10.5)	$ 6.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 157.2	$ 364.0	$ 724.7	$ 2.1	$ 1,248.0
Common Stock Dividends			(11.3)		(11.3)
Net Income			6.2		6.2
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	$ 157 2	$ 364.0	$ 719 6	$ 1.9	$ 1,242.7
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 157.2	$ 364.0	$ 851 0	$ 1 1	$ 1,373.3
ASU 2016-13 Adoption			0 3		0.3
Net Loss			(10.3)		(10.3)
Other Comprehensive Loss				(0 2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	$ 157.2	$ 364.0	$ 841.0	$ 0.9	$ 1,363.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2020 and December 31, 2019
(in millions)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.1	$ 1.5
Advances to Affiliates	—	38 8
Accounts Receivable:		
Customers	28.4	28.9
Affiliated Companies	19.9	20.6
Miscellaneous	0.8	0.6
Allowance for Uncollectible Accounts	(0.2)	(0.3)
Total Accounts Receivable	48.9	49.8
Fuel	19.6	12.2
Materials and Supplies	47.9	46 8
Risk Management Assets	6.4	15.8
Accrued Tax Benefits	5.7	11 3
Prepayments and Other Current Assets	13.4	12.0
TOTAL CURRENT ASSETS	143.0	188.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,577.2	1,574.6
Transmission	959.5	948.5
Distribution	2,724.3	2,684.8
Other Property, Plant and Equipment	350.3	342.1
Construction Work in Progress	144 9	133.4
Total Property, Plant and Equipment	5,756.2	5,683.4
Accumulated Depreciation and Amortization	1,615 8	1,580.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,140.4	4,103.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	378 4	375 2
Employee Benefits and Pension Assets	44.2	43.9
Operating Lease Assets	38.0	36.8
Deferred Charges and Other Noncurrent Assets	34.0	4.1
TOTAL OTHER NONCURRENT ASSETS	494.6	460.0
TOTAL ASSETS	$ 4,778 0	$ 4,751.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2020 and December 31, 2019
(Unaudited)

	March 31, 2020	December 31, 2019
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 70.9	$ —
Accounts Payable:		
General	102.5	134.3
Affiliated Companies	39.8	59 3
Long-term Debt Due Within One Year – Nonaffiliated	263.2	13.2
Risk Management Liabilities	0.1	—
Customer Deposits	59.3	58.9
Accrued Taxes	42.4	22.9
Obligations Under Operating Leases	6.0	5.8
Regulatory Liability for Over-Recovered Fuel Costs	68.0	63.9
Other Current Liabilities	78.6	87.5
TOTAL CURRENT LIABILITIES	730.8	445.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,123.1	1,373.0
Deferred Income Taxes	629.6	628.3
Regulatory Liabilities and Deferred Investment Tax Credits	835.0	837.2
Asset Retirement Obligations	45.3	44 5
Obligations Under Operating Leases	32.1	31.0
Deferred Credits and Other Noncurrent Liabilities	19.0	18 4
TOTAL NONCURRENT LIABILITIES	2,684.1	2,932.4
TOTAL LIABILITIES	3,414.9	3,378.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	841.0	851.0
Accumulated Other Comprehensive Income (Loss)	0.9	1.1
TOTAL COMMON SHAREHOLDER'S EQUITY	1,363 1	1,373.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,778 0	$ 4,751.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31, 2020	2019
OPERATING ACTIVITIES		
Net Income (Loss)	$ (10.3)	$ 6.2
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	44 7	43 5
Deferred Income Taxes	(5 3)	(5 8)
Allowance for Equity Funds Used During Construction	(1 0)	(0.1)
Mark-to-Market of Risk Management Contracts	9 5	5 1
Property Taxes	(29.8)	(29.9)
Deferred Fuel Over/Under-Recovery, Net	4 1	(2 4)
Change in Other Noncurrent Assets	(0.1)	8.0
Change in Other Noncurrent Liabilities	4 2	(0 7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	0 9	2 0
Fuel, Materials and Supplies	(8 5)	3.2
Accounts Payable	(39 1)	(23 3)
Accrued Taxes, Net	25.1	25.3
Other Current Assets	(1 7)	(3 8)
Other Current Liabilities	(7 2)	4.4
Net Cash Flows from (Used for) Operating Activities	(14 5)	31 7
INVESTING ACTIVITIES		
Construction Expenditures	(96 5)	(70.7)
Change in Advances to Affiliates, Net	38 8	—
Other Investing Activities	1.6	0 4
Net Cash Flows Used for Investing Activities	(56 1)	(70 3)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	99.9
Change in Advances from Affiliates, Net	70 9	(50 3)
Retirement of Long-term Debt – Nonaffiliated	(0 1)	(0.1)
Principal Payments for Finance Lease Obligations	(0 8)	(0 7)
Dividends Paid on Common Stock	—	(11.3)
Other Financing Activities	0 2	0 6
Net Cash Flows from Financing Activities	70.2	38.1
Net Decrease in Cash and Cash Equivalents	(0.4)	(0.5)
Cash and Cash Equivalents at Beginning of Period	1 5	2 0
Cash and Cash Equivalents at End of Period	$ 1.1	$ 1.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 16 7	$ 10 9
Net Cash Paid for Income Taxes	—	0.6
Noncash Acquisitions Under Finance Leases	0 9	1 1
Construction Expenditures Included in Current Liabilities as of March 31,	30 8	15 6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	1,406	1,528
Commercial	1,228	1,273
Industrial	1,242	1,250
Miscellaneous	20	20
Total Retail	3,896	4,071
Wholesale	1,326	1,979
Total KWhs	5,222	6,050

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2020	2019
	(in degree days)	
Actual – Heating (a)	497	708
Normal – Heating (b)	698	698
Actual – Cooling (c)	69	20
Normal – Cooling (b)	39	39

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

First Quarter of 2019	$	27.8
Changes in Gross Margin:		
Retail Margins (a)		(4.2)
Margins from Off-system Sales		(1.6)
Transmission Revenues		4.8
Other Revenues		(0.3)
Total Change in Gross Margin		(1.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		(12.5)
Depreciation and Amortization		(5.2)
Interest Income		(0.1)
Allowance for Equity Funds Used During Construction		(0.4)
Interest Expense		(0.4)
Total Change in Expenses and Other		(18.6)
Income Tax Expense		6.9
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interest		0.2
First Quarter of 2020	$	15.1

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $4 million primarily due to the following:
  - An $8 million decrease in weather-normalized margins.
  - A $5 million decrease in weather-related usage primarily due to a 30% decrease in heating degree days.
  - A $3 million decrease due to an increase in the return of Excess ADIT benefits to customers. This decrease was offset in Income Tax Expense (Benefit) below.

  These decreases were partially offset by:
  - An $11 million increase primarily due to capital investment rider and base rate revenue increases in Texas, Arkansas and Louisiana.
- **Transmission Revenues** increased $5 million primarily due to an increase in SPP transmission services revenue.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $5 million increase in storm-related expenses.
  - A $3 million increase in SPP transmission expenses.
  - A $2 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base and an increase in Arkansas depreciation rates beginning in January 2020. This increase was partially offset within Retail Margins above.
- **Income Tax Expense** decreased $7 million primarily due to a decrease in pretax book income and an increase in amortization of excess ADIT. The increase in amortization of excess ADIT was partially offset in Retail Margins above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	**2019**
REVENUES		
Electric Generation, Transmission and Distribution	$ 377.6	$ 414.3
Sales to AEP Affiliates	7.5	6.4
Other Revenues	0.8	0.4
TOTAL REVENUES	385.9	421.1
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	89.1	133.5
Purchased Electricity for Resale	43.1	32 6
Other Operation	92.2	84.6
Maintenance	33.8	28.9
Depreciation and Amortization	67.3	62.1
Taxes Other Than Income Taxes	25.3	25.3
TOTAL EXPENSES	350.8	367.0
OPERATING INCOME	35.1	54.1
Other Income (Expense):		
Interest Income	0 6	0.7
Allowance for Equity Funds Used During Construction	1.4	1.8
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2 1
Interest Expense	(30.1)	(29.7)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	9.1	29.0
Income Tax Expense (Benefit)	(6.2)	0.7
Equity Earnings of Unconsolidated Subsidiary	0.8	0.7
NET INCOME	16.1	29.0
Net Income Attributable to Noncontrolling Interest	1.0	1.2
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 15.1	$ 27.8

The common stock of SWEPCo ıs wholly-owned by Parent.

See Condensed Notes to Condensed Fınancıal Statements of Regıstrants begınnıng on page 110

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2020	2019
Net Income	$ 16.1	$ 29.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 in 2020 and 2019, Respectively	0 4	0.4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) in 2020 and 2019, Respectively	(0.4)	(0.3)
TOTAL OTHER COMPREHENSIVE INCOME	—	0.1
TOTAL COMPREHENSIVE INCOME	16.1	29.1
Total Comprehensive Income Attributable to Noncontrolling Interest	1.0	1.2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 15.1	$ 27.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2018	$ 135.7	$ 676.6	$ 1,508.4	$ (5.4)	$ 0.3	$ 2,315.6
Common Stock Dividends			(18.7)			(18.7)
Common Stock Dividends – Nonaffiliated					(1 1)	(1 1)
Net Income			27.8		1.2	29 0
Other Comprehensive Income				0 1		0 1
TOTAL EQUITY – MARCH 31, 2019	$ 135.7	$ 676.6	$ 1,517.5	$ (5 3)	$ 0.4	$ 2,324.9
TOTAL EQUITY – DECEMBER 31, 2019	$ 135.7	$ 676.6	$ 1,629.5	$ (1.3)	$ 0 6	$ 2,441.1
Common Stock Dividends – Nonaffiliated					(0.7)	(0 7)
ASU 2016-13 Adoption			1 6			1 6
Net Income			15.1		1.0	16.1
TOTAL EQUITY – MARCH 31, 2020	$ 135 7	$ 676 6	$ 1,646 2	$ (1 3)	$ 0 9	$ 2,458 1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2020 and December 31, 2019
(in millions)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.4	$ 1.6
Advances to Affiliates	2.1	2.1
Accounts Receivable:		
Customers	25.6	29.0
Affiliated Companies	24.4	34.5
Miscellaneous	14 3	13.5
Allowance for Uncollectible Accounts	(0.3)	(1.7)
Total Accounts Receivable	64.0	75.3
Fuel (March 31, 2020 and December 31, 2019 Amounts Include $42 and $47, Respectively, Related to Sabine)	147.9	140.1
Materials and Supplies (March 31, 2020 and December 31, 2019 Amounts Include $23 3 and $23.1, Respectively, Related to Sabine)	93.8	94.0
Risk Management Assets	2.6	6.4
Regulatory Asset for Under-Recovered Fuel Costs	—	4.9
Prepayments and Other Current Assets	34.3	29.7
TOTAL CURRENT ASSETS	346 1	354.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,703.0	4,691.4
Transmission	2,061.6	2,056.5
Distribution	2,300.8	2,270.7
Other Property, Plant and Equipment (March 31, 2020 and December 31, 2019 Amounts Include $213.5 and $212.3, Respectively, Related to Sabine)	767.2	733.4
Construction Work in Progress	232.7	216.9
Total Property, Plant and Equipment	10,065.3	9,968.9
Accumulated Depreciation and Amortization (March 31, 2020 and December 31, 2019 Amounts Include $112 and $107.5, Respectively, Related to Sabine)	2,918.7	2,873.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,146.6	7,095.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	236.6	222.4
Deferred Charges and Other Noncurrent Assets	214.8	160.5
TOTAL OTHER NONCURRENT ASSETS	451.4	382.9
TOTAL ASSETS	$ 7,944 1	$ 7,832.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2020 and December 31, 2019
(Unaudited)

	March 31, 2020	December 31, 2019
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 148.1	$ 59.9
Accounts Payable.		
General	102.5	138.0
Affiliated Companies	37.3	53.6
Short-term Debt – Nonaffiliated	30.5	18.3
Long-term Debt Due Within One Year – Nonaffiliated	121.2	121.2
Risk Management Liabilities	2.2	1.9
Customer Deposits	65.1	65.0
Accrued Taxes	93.0	41.8
Accrued Interest	21.9	34.6
Obligations Under Operating Leases	7.1	6.5
Regulatory Liability for Over-Recovered Fuel Costs	29.7	13.6
Other Current Liabilities	87.8	120.3
TOTAL CURRENT LIABILITIES	746.4	674.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,533.2	2,534.4
Long-term Risk Management Liabilities	2 9	3.1
Deferred Income Taxes	944.4	940.9
Regulatory Liabilities and Deferred Investment Tax Credits	885 8	892.3
Asset Retirement Obligations	219.7	196.7
Obligations Under Operating Leases	38.2	34.7
Deferred Credits and Other Noncurrent Liabilities	115.4	114.3
TOTAL NONCURRENT LIABILITIES	4,739.6	4,716.4
TOTAL LIABILITIES	5,486.0	5,391 1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,646 2	1,629.5
Accumulated Other Comprehensive Income (Loss)	(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,457.2	2,440.5
Noncontrolling Interest	0.9	0 6
TOTAL EQUITY	2,458.1	2,441.1
TOTAL LIABILITIES AND EQUITY	$ 7,944.1	$ 7,832.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31, 2020	2019
OPERATING ACTIVITIES		
Net Income	$ 16.1	$ 29.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	67.3	62.1
Deferred Income Taxes	(9 2)	(2 5)
Allowance for Equity Funds Used During Construction	(1 4)	(1.8)
Mark-to-Market of Risk Management Contracts	3 9	2 3
Property Taxes	(49 0)	(48.9)
Deferred Fuel Over/Under-Recovery, Net	21 0	10 3
Change in Other Noncurrent Assets	(4 0)	2.9
Change in Other Noncurrent Liabilities	9 8	7 9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	11 3	6 3
Fuel, Materials and Supplies	(7.6)	(16 2)
Accounts Payable	(31 2)	(55 0)
Accrued Taxes, Net	51 2	52.7
Accrued Interest	(12.7)	(12 7)
Other Current Assets	(4.0)	(10.0)
Other Current Liabilities	(35 7)	(17 0)
Net Cash Flows from Operating Activities	25.8	9.4
INVESTING ACTIVITIES		
Construction Expenditures	(122 4)	(86.6)
Change in Advances to Affiliates, Net	—	81.4
Other Investing Activities	0 8	(3 1)
Net Cash Flows Used for Investing Activities	(121.6)	(8.3)
FINANCING ACTIVITIES		
Change in Short-term Debt – Nonaffiliated	12 2	—
Change in Advances from Affiliates, Net	88.2	74.0
Retirement of Long-term Debt – Nonaffiliated	(1 6)	(55 1)
Principal Payments for Finance Lease Obligations	(2.7)	(2.7)
Dividends Paid on Common Stock	—	(18 7)
Dividends Paid on Common Stock – Nonaffiliated	(0.7)	(1.1)
Other Financing Activities	0 2	0 1
Net Cash Flows from (Used for) Financing Activities	95.6	(3.5)
Net Decrease in Cash and Cash Equivalents	(0 2)	(2.4)
Cash and Cash Equivalents at Beginning of Period	1 6	24 5
Cash and Cash Equivalents at End of Period	$ 1.4	$ 22.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 40 7	$ 40.5
Net Cash Paid for Income Taxes	—	0.2
Noncash Acquisitions Under Finance Leases	3 0	0 8
Construction Expenditures Included in Current Liabilities as of March 31,	45 2	44.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

The condensed notes to condensed financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise:

1. SIGNIFICANT ACCOUNTING MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three months ended March 31, 2020 is not necessarily indicative of results that may be expected for the year ending December 31, 2020. The condensed financial statements are unaudited and should be read in conjunction with the audited 2019 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 20, 2020.

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. The Registrants are taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19.

As of March 31, 2020 and through the date of this report, the Registrants assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, the allowance for credit losses and the carrying value of long-lived assets. While there were not any impairments or significant increases in credit allowances resulting from these assessments as of and for the quarter ended March 31, 2020, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

Earnings Per Share (EPS) (Applies to AEP)

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted-average outstanding common shares, assuming conversion of all potentially dilutive stock awards.

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Three Months Ended March 31,			
	2020		2019	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 495.2		$ 572.8	
Weighted Average Number of Basic Shares Outstanding	494.6	$ 1.00	493.3	$ 1.16
Weighted Average Dilutive Effect of Stock-Based Awards	2.0	—	1.2	—
Weighted Average Number of Diluted Shares Outstanding	496.6	$ 1.00	494.5	$ 1.16

Equity Units issued in March 2019 are potentially dilutive securities but were excluded from the calculation of diluted EPS for the three months ended March 31, 2020 and 2019, as the dilutive stock price threshold was not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were 697 thousand and 0 antidilutive shares outstanding as of March 31, 2020 and 2019, respectively. The antidilutive shares were excluded from the calculation of diluted EPS.

Restricted Cash (Applies to AEP, AEP Texas and APCo)

Restricted Cash primarily included funds held by trustee for the payment of securitization bonds and contractually restricted deposits held for the future payment of the remaining construction activities at Santa Rita East.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the balance sheets that sum to the total of the same amounts shown on the statements of cash flows:

	March 31, 2020		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 1,554.6	$ 0.1	$ 2.8
Restricted Cash	116.2	100.1	15.7
Total Cash, Cash Equivalents and Restricted Cash	$ 1,670.8	$ 100.2	$ 18.5

	December 31, 2019		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 246.8	$ 3.1	$ 3.3
Restricted Cash	185.8	154.7	23.5
Total Cash, Cash Equivalents and Restricted Cash	$ 432.6	$ 157.8	$ 26.8

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. The assessment is performed separately by each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified. In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for Credit Losses. Management's assessments contemplate expected losses over the life of the accounts receivable.

2. NEW ACCOUNTING STANDARDS

The disclosures in this note apply to all Registrants unless indicated otherwise.

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following standards will impact the financial statements.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

New standard implementation activities included: (a) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard, (b) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information and (c) the development of disclosures to comply with the requirements of ASU 2016-13. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of an immaterial cumulative-effect adjustment to Retained Earnings on the balance sheets. The adoption of the new standard did not have a material impact to financial position and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

ASU 2020-04 "Reference Rate Reform: Facilitation of the Effects of Reference Rate Reform on Financial Reporting" (ASU 2020-04)

In March 2020, the FASB issued ASU 2020-04 providing guidance to ease the potential burden in accounting for Reference Rate Reform on financial reporting. The new standard is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference the London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of Reference Rate Reform. The new standard establishes a general contract modification principle that entities can apply in other areas that may be affected by Reference Rate Reform and certain elective hedge accounting expedients. Under the new standard, an entity may make a one-time election to sell or to transfer to the available-for-sale or trading classifications (or both sell and transfer), debt securities that both reference an affected rate, and were classified as held-to-maturity before January 1, 2020.

The new accounting guidance is effective for all entities as of March 12, 2020 through December 31, 2022. The amendments may be applied to contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. The amendments may be applied to eligible hedging relationships existing as of the beginning of the interim period that includes March 12, 2020 and to new eligible hedging relationships entered into after the beginning of the interim period that includes March 12, 2020. The one-time election to sell, transfer, or both sell and transfer debt securities classified as held-to-maturity may be made at any time after March 12, 2020 but no later than December 31, 2022. Management has yet to apply the amendments in the new standard to any contract modifications, hedging relationships, or debt securities. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

AEP

	Cash Flow Hedges		Pension	
Three Months Ended March 31, 2020	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ (32.7)	$ (147.7)
Change in Fair Value Recognized in AOCI	(65 3)	(42 7) (a)	—	(108 0)
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	(0 1)	—	—	(0 1)
Purchased Electricity for Resale (b)	51.1	—	—	51 1
Interest Expense (b)	—	0 9	—	0 9
Amortization of Prior Service Cost (Credit)	—	—	(4.9)	(4 9)
Amortization of Actuarial (Gains) Losses	—	—	2.6	2 6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	51.0	0 9	(2.3)	49 6
Income Tax (Expense) Benefit	10 7	0 2	(0.5)	10 4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	40.3	0 7	(1.8)	39 2
Net Current Period Other Comprehensive Income (Loss)	(25 0)	(42 0)	(1 8)	(68 8)
Balance in AOCI as of March 31, 2020	$ (128.5)	$ (53.5)	$ (34.5)	$ (216.5)

	Cash Flow Hedges		Pension	
Three Months Ended March 31, 2019	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ (84 8)	$ (120 4)
Change in Fair Value Recognized in AOCI	(38.8)	—	—	(38 8)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (b)	12.3	—	—	12.3
Interest Expense (b)	—	0.2	—	0.2
Amortization of Prior Service Cost (Credit)	—	—	(4 8)	(4 8)
Amortization of Actuarial (Gains) Losses	—	—	3 0	3.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	12 3	0 2	(1.8)	10 7
Income Tax (Expense) Benefit	2.6	—	(0.4)	2.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	9 7	0 2	(1.4)	8 5
Net Current Period Other Comprehensive Income (Loss)	(29.1)	0.2	(1.4)	(30 3)
Balance in AOCI as of March 31, 2019	$ (52 1)	$ (12 4)	$ (86 2)	$ (150 7)

AEP Texas

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (3 4)	$ (9.4)	$ (12.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 4	—	0 4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0 4	—	0 4
Income Tax (Expense) Benefit	0 1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0 3
Net Current Period Other Comprehensive Income (Loss)	0 3	—	0.3
Balance in AOCI as of March 31, 2020	$ (3.1)	$ (9.4)	$ (12.5)

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (4.4)	$ (10.7)	$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 4	—	0 4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0 1	—	0 1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0 3	—	0 3
Balance in AOCI as of March 31, 2019	$ (4.1)	$ (10.7)	$ (14.8)

APCo

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ 0.9	$ 4.1	$ 5.0
Change in Fair Value Recognized in AOCI	(3 9)	—	(3 9)
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0 4)	—	(0 4)
Amortization of Prior Service Cost (Credit)	—	(1 3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	0 1	0 1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.4)	(1.2)	(1 6)
Income Tax (Expense) Benefit	(0 1)	(0 3)	(0 4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.3)	(0 9)	(1 2)
Net Current Period Other Comprehensive Income (Loss)	(4 2)	(0 9)	(5 1)
Balance in AOCI as of March 31, 2020	$ (3.3)	$ 3 2	$ (0.1)

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ 1.8	$ (6.8)	$ (5.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0 3)	—	(0 3)
Amortization of Prior Service Cost (Credit)	—	(1 3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	0 5	0 5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)	(0.8)	(1.1)

Income Tax (Expense) Benefit	(0 1)	(0 2)	(0 3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0 2)	(0.6)	(0 8)
Net Current Period Other Comprehensive Income (Loss)	(0 2)	(0 6)	(0 8)
Balance in AOCI as of March 31, 2019	$ 1.6	$ (7.4)	$ (5 8)

I&M

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (9 9)	$ (1.7)	$ (11.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 5	—	0 5
Amortization of Prior Service Cost (Credit)	—	(0 2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0 2	0 2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	—	0.5
Income Tax (Expense) Benefit	0 1	—	0 1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	—	0.4
Net Current Period Other Comprehensive Income (Loss)	0 4	—	0 4
Balance in AOCI as of March 31, 2020	$ (9 5)	$ (1.7)	$ (11 2)

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (11.5)	$ (2 3)	$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 5	—	0 5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0 2	0 2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0 5	—	0.5
Income Tax (Expense) Benefit	0 1	—	0 1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0 4	—	0.4
Net Current Period Other Comprehensive Income (Loss)	0 4	—	0 4
Balance in AOCI as of March 31, 2019	$ (11.1)	$ (2 3)	$ (13.4)

OPCo

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of March 31, 2020	$ —

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 1.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0 4)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.4)

Income Tax (Expense) Benefit		(0 1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(0 3)
Net Current Period Other Comprehensive Income (Loss)		(0 3)
Balance in AOCI as of March 31, 2019	$	0 7

PSO

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ 1.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)
Income Tax (Expense) Benefit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.2)
Net Current Period Other Comprehensive Income (Loss)	(0.2)
Balance in AOCI as of March 31, 2020	$ 0.9

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 2.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0 3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)
Income Tax (Expense) Benefit	(0 1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0 2)
Net Current Period Other Comprehensive Income (Loss)	(0 2)
Balance in AOCI as of March 31, 2019	$ 1.9

SWEPCo

Three Months Ended March 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (1 8)	$ 0.5	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 5	—	0 5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0 5	(0 5)	—
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0 4	(0 4)	—
Net Current Period Other Comprehensive Income (Loss)	0.4	(0 4)	—
Balance in AOCI as of March 31, 2020	$ (1 4)	$ 0 1	$ (1 3)

Three Months Ended March 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (2.1)	$ (5.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0 5	—	0 5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains) Losses	—	0 1	0 1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.4)	0.1
Income Tax (Expense) Benefit	0 1	(0 1)	—

Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0 4	(0 3)	0.1
Net Current Period Other Comprehensive Income (Loss)	0 4	(0 3)	0 1
Balance in AOCI as of March 31, 2019	$ (2.9)	$ (2.4)	$ (5.3)

(a) The change in fair value includes $5 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the three months ended March 31, 2020

(b) Amounts reclassified to the referenced line item on the statements of income

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

As discussed in the 2019 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2019 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2020 and updates the 2019 Annual Report.

Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is expected to be retired by October 2020.

In January 2020, as part of the 2019 Arkansas Base Rate Case, management announced that the Dolet Hills Power Station was probable of abandonment and was to be retired by December 2026. In March 2020, management announced plans to accelerate the expected retirement date to the end of September 2021.

The table below summarizes the plant investment and their cost of removal, currently being recovered, as well as the regulatory assets for accelerated depreciation for the generating units as of March 31, 2020.

Plant	Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
				(dollars in millions)				
Oklaunion Power Station	$ 106 8	$ 92 6	$ 14 2	$ 33 0 (a)	$ 3 3	$ 5 2	2020	27 years
Dolet Hills Power Station	341 4	205 0	136 4	9 1 (b)	5 8	23 7	2021	27 years

(a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station

(b) In January 2020, SWEPCo changed depreciation rates to utilize the 2026 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously APSC-approved depreciation rates for Dolet Hills Power Station In March 2020, SWEPCo changed depreciation rates again to utilize the accelerated 2021 end-of-life

Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo's settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. DHLC provides 100% of the fuel supply to Dolet Hills Power Station. In March 2020, it was determined that DHLC would not proceed developing additional mining areas for future lignite extraction and management notified a substantial portion of its workforce that employment will permanently end in June 2020. Based on these actions, management has revised the estimated useful life of many of DHLC's assets to June 2020 to coincide with the date at which extraction is expected to be discontinued. Management also revised the useful life of the Dolet Hills Power Station to September 2021 based on the remaining estimated fuel supply available for continued seasonal operation. In March 2020, primarily due to the revision in the useful life of DHLC, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the pending cessation of lignite mining in June 2020.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $151 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of March 31, 2020, DHLC has unbilled lignite inventory and fixed costs of $124 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of March 31, 2020, Oxbow has unbilled fixed costs of $26 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulatory Assets Pending Final Regulatory Approval (Applies to all Registrants except AEPTCo)

	AEP	
	March 31, 2020	**December 31, 2019**
Noncurrent Regulatory Assets	**(in millions)**	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Unrecovered Plant	$ 35.2	$ 35.2
Oklaunion Power Station Accelerated Depreciation	33.0	27.4
Kentucky Deferred Purchase Power Expenses	32.9	30.2
Dolet Hills Power Station Accelerated Depreciation	9.1	—
Other Regulatory Assets Pending Final Regulatory Approval	2.1	0.7
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	30.1
Asset Retirement Obligation	7.7	7.2
Storm-Related Costs	7.3	7.2
Vegetation Management Program (a)	3.8	29.4
Cook Plant Study Costs (b)	—	7.6
Other Regulatory Assets Pending Final Regulatory Approval	5.0	6.7
Total Regulatory Assets Pending Final Regulatory Approval (c)	$ 162.0	$ 181.7

(a) In April 2020, $26 million of deferred expenses were approved for recovery. See “2019 Texas Base Rate Case” section below for additional information.
(b) Approved for recovery in the first quarter of 2020 in the Indiana Base Rate Case.
(c) APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of March 31, 2020 and December 31, 2019, APCo has approximately $52 million and $51 million, respectively, of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo is pursuing full recovery of these assets through its Virginia depreciation rates. See “2017-2019 Virginia Triennial Review” section below for additional information.

	AEP Texas	
	March 31, 2020	**December 31, 2019**
Noncurrent Regulatory Assets	**(in millions)**	
Regulatory Assets Currently Not Earning a Return		
Vegetation Management Program (a)	$ 3.8	$ 29.4
Other Regulatory Assets Pending Final Regulatory Approval	1.5	1.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 5.3	$ 30.8

(a) In April 2020, $26 million of deferred expenses were approved for recovery. See “2019 Texas Base Rate Case” section below for additional information.

Noncurrent Regulatory Assets	APCo March 31, 2020	APCo December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Materials and Supplies	$ —	$ 0.5
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	30.1
Total Regulatory Assets Pending Final Regulatory Approval (a)	$ 25.9	$ 30.6

(a) APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of March 31, 2020 and December 31, 2019, APCo has approximately \$52 million and \$51 million, respectively, of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo is pursuing full recovery of these assets through its Virginia depreciation rates. See "2017-2019 Virginia Triennial Review" section below for additional information.

Noncurrent Regulatory Assets	I&M March 31, 2020	I&M December 31, 2019
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Study Costs (a)	$ —	$ 7.6
Other Regulatory Assets Pending Final Regulatory Approval	—	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ —	$ 7.7

(a) Approved for recovery in the first quarter of 2020 in the Indiana Base Rate Case.

Noncurrent Regulatory Assets	OPCo March 31, 2020	OPCo December 31, 2019
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 0.1

Noncurrent Regulatory Assets	PSO March 31, 2020	PSO December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
Oklaunion Power Station Accelerated Depreciation	$ 33.0	$ 27.4
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	7.3	7.2
Total Regulatory Assets Pending Final Regulatory Approval	$ 40.3	$ 34.6

Noncurrent Regulatory Assets	SWEPCo March 31, 2020	SWEPCo December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Unrecovered Plant, Louisiana	$ 35.2	$ 35.2
Dolet Hills Power Station Accelerated Depreciation	9.1	—
Other Regulatory Assets Pending Final Regulatory Approval	2.2	0.2
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation - Louisiana	7.7	7.2
Other Regulatory Assets Pending Final Regulatory Approval	1.9	3.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 56.1	$ 46.3

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

COVID-19 Pandemic

AEP's electric utility operating companies have informed retail customers and state regulators that disconnections for non-payment have been temporarily suspended. These uncertain economic conditions may result in the inability of customers to pay for electric service, which could affect the collectability of the Registrants revenues and adversely affect financial results. The Registrants are currently evaluating and working with regulatory commissions on potential rate recovery for increased costs as a result of the impacts of COVID-19. If any costs related to COVID-19 are not recoverable, it could reduce future net income and cash flows and impact financial condition. The table below describes the key elements of orders received, by jurisdiction, in response to COVID-19:

Company	Jurisdiction	Order
AEP Texas, ETT, SWEPCo	Texas	• Established a COVID-19 Electricity Relief Program to be funded through a rider for eligible residential customers in the areas of the state open to customer choice (AEP Texas only). • Granted permission for utilities to record a regulatory asset for expenses including, but not limited to, non-payment of qualified customer bills who have been affected by the COVID-19 pandemic.
APCo	Virginia	• Granted permission for utilities to defer expenses related to the COVID-19 pandemic. Deferral will be subject to APCo's Virginia earnings test during the 2020-2022 Triennial period.
I&M	Michigan	• Granted permission for utilities to defer certain expenses related to the COVID-19 pandemic.
SWEPCo	Arkansas	• Granted permission for utilities to establish a regulatory asset to record costs resulting from the suspension of disconnections offset by any cost savings directly attributable to the suspension of disconnections or other activities during the COVID-19 pandemic.
SWEPCo	Louisiana	• Granted permission for utilities to record a regulatory asset for expenses resulting from the suspension of disconnections and collection of late fees related to the COVID-19 pandemic.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

2019 Texas Base Rate Case

In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. The filing included a proposed Income Tax Refund Rider that will refund $21 million annually of Excess ADIT that is primarily not subject to normalization requirements. The rate case also sought a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019.

In April 2020, the PUCT issued an order approving a stipulation and settlement agreement. The order includes an annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity effective with the first billing cycle in June 2020. The order provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The order includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. The order requires AEP Texas to file its next base rate case within four years of the date of that the final order was issued. The order also states future financially based capital incentives will not be included in interim transmission and distribution rates and contains various ring-fencing provisions. As a result of the final order, AEP Texas will refund $275 million of Excess ADIT associated with certain depreciable property using ARAM to transmission customers. AEP Texas will determine how to refund the remaining Excess ADIT that is not subject to normalization requirements in future proceedings.

In December 2019, as a result of the initial stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million related to capital investments, which included $10 million of 2019 investments, in Asset Impairments and Other Related Charges on the statements of income, (b) recorded a $30 million provision for refund on the statements of income for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses to Other Operation on the statements of income.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

2017-2019 Virginia Triennial Review

Amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that required APCo to file a generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 earnings test years (triennial review). Triennial reviews are subject to an earnings test, which provides that 70% of any earnings in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. In such case, the Virginia SCC could also lower APCo's Virginia retail base rates on a prospective basis. In November 2018, the Virginia SCC authorized a ROE of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period.

Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. In 2015, APCo retired the Sporn Plant, the Kanawha River Plant, the Glen Lyn Plant, Clinch River Unit 3 and the coal portions of Clinch River Units 1 and 2 (collectively, the retired coal-fired generation assets). The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory and ARO balances. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

In March 2020, APCo submitted its 2017-2019 Virginia triennial earnings review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $65 million annual increase based upon a proposed 9.9% return on common equity. The requested annual increase includes $19 million related to depreciation for updated test year end depreciable balances and a proposed increase in APCo's Virginia depreciation rates and $8 million related to APCo's calculated shortfall in 2017-2019 APCo's Virginia earnings. Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo calculated its 2017-2019 Virginia earnings for the triennial period to be below the authorized ROE range.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of March 31, 2020 and December 31, 2019, APCo has approximately $52 million and $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo is pursuing full recovery of these assets through its Virginia depreciation rates as discussed above.

If any APCo Virginia jurisdictional costs are not recoverable or if refunds of revenues collected from customers during the triennial review period are ordered by the Virginia SCC, it could reduce future net income and cash flows and impact financial condition.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through March 31, 2020, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1.1 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for base rate proceedings. The rule requires ETT to file for a comprehensive base rate review no later than February 1, 2021.

I&M Rate Matters (Applies to AEP and I&M)

2019 Indiana Base Rate Case

In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and was based upon a proposed 10.5% return on common equity. The proposed annual increase included $78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense included $52 million related to proposed investments and $26 million related to increased depreciation rates. The request included the continuation of all existing riders and a new AMI rider for proposed meter projects.

In March 2020, the IURC issued an order authorizing a $77 million annual base rate increase based upon a return on common equity of 9.7% effective March 2020. This increase will be phased in through January 2021 with an approximate $44 million annual increase in base rates effective March 2020 and the full $77 million annual increase effective January 2021. The order approved the majority of I&M's proposed changes in depreciation. The order also approved the test year level of AMI deployment but did not approve a cost recovery rider for AMI investments made in subsequent years. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which will negatively impact I&M's annual pretax earnings by approximately $20 million starting June 2020. In March 2020, I&M filed for rehearing as a result of the IURC's ruling to reject I&M's proposed re-allocation of capacity costs. Intervenors subsequently filed objections to I&M's appeal. In April 2020, I&M filed a reply to these objections on rehearing and appealed the IURC's order.

<u>OPCo Rate Matters</u> (Applies to AEP and OPCo)

2020 Ohio Base Rate Case

In April 2020, OPCo filed a pre-filing notice stating its intent to file an application with the PUCO to adjust distribution rates. OPCo plans to file the application in May 2020 and also plans to request a temporary delay of the normal rate case proceeding due to the COVID-19 pandemic.

<u>SWEPCo Rate Matters</u> (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court.

As of March 31, 2020, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in- service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and included SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. In June 2019, the LPSC staff issued its report which reaffirmed its $11 million refund recommendation. The report also contends that SWEPCo's requested annual rate increase of $18 million, which was implemented in August 2018, is overstated by $4 million and proposes an annual rate increase of $14 million. Additionally, the report recommends SWEPCo refund the excess over-collections associated with the $4 million difference for the period of August 2018 through the implementation of new rates. In July 2019, the LPSC approved the $11 million refund. A decision by the LPSC on the remaining formula rate plan issues is expected in the second quarter of 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants' business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2019 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Letters of Credit (Applies to AEP, AEP Texas and OPCo)

Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has a $4 billion revolving credit facility due in June 2022, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of March 31, 2020, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2020 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 241.2	April 2020 to March 2021
AEP Texas	2.2	July 2020
OPCo (a)	1.0	April 2021

(a) In April 2020, the maturity date was extended from April 2020 to April 2021.

Guarantees of Equity Method Investees (Applies to AEP)

In April 2019, AEP acquired Sempra Renewables LLC. See "Acquisitions" section of Note 6 for additional information.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2020, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase-and-sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase-and-sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of March 31, 2020, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 48.5
AEP Texas	11.6
APCo	6.6
I&M	4.3
OPCo	7.6
PSO	4.4
SWEPCo	4.9

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The Owner Trustee owns the Plant and leases equal portions to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. The option to renew was not included in the measurement of the lease obligation as of March 31, 2020 as the execution of the option was not reasonably certain. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt.

The future minimum lease payments for this sale-and-leaseback transaction as of March 31, 2020 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2020	$ 147.8	$ 73.9
2021	147.8	73.9
2022	147.5	73.7
Total Future Minimum Lease Payments	$ 443.1	$ 221.5

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the respective lessors, ensuring future payments under such leases with maturities up to 2027. As of March 31, 2020, the maximum potential amount of future payments required under the guaranteed leases was $53 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of March 31, 2020, AEP's boat and barge lease guarantee liability was $4 million, of which $1 million was recorded in Other Current Liabilities and $3 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

In February 2020, the nonaffiliated party filed Chapter 11 bankruptcy. The party entered into a restructuring support agreement and has announced it expects to continue their operations as normal. In March 2020, the bankruptcy court approved the party's recapitalization plan. In April 2020, the nonaffiliated party emerged from bankruptcy. Management has determined that it is reasonably possible that enforcement of AEP's liability for future payments under these leases will be exercised within the next twelve months. In such an event, if AEP is unable to sell or incorporate any of the acquired assets into its fleet operations, it could reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely. For remediation processes not specifically discussed, management does not anticipate that the liabilities, if any, arising from such remediation processes would have a material effect on the financial statements.

Virginia House Bill 443 (Applies to AEP and APCo)

In March 2020, Virginia's Governor signed House Bill 443 (HB 443) requiring APCo to close ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. APCo's current ARO for these units is based on closure in place and will require future revision to reflect the costs of closure by removal. As of March 31, 2020, APCo is unable to reasonably estimate this cost due to the recent passage of the legislation. Management expects to record a material revision to the ARO after engineering plans for the removal are developed later in 2020. The closure is required to be completed within 15 years from the start of the excavation process. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause (E-RAC). APCo may begin deferring incurred costs on July 1, 2020 and recovering these costs through the E-RAC beginning

July 1, 2022. APCo is permitted to record carrying costs on the unrecovered balance of closure costs at a weighted average cost of capital approved by the Virginia SCC. HB 443 also allows any closure costs allocated to non-Virginia jurisdictional customers, but not collected from such non-Virginia jurisdictional customers, to be recovered from Virginia jurisdictional customers through the E-RAC. Management does not expect HB 443 to materially impact results of operations or cash flows, but does anticipate a material impact to APCo's balance sheet.

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

I&M owns and operates the Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

OPERATIONAL CONTINGENCIES

Rockport Plant Litigation (Applies to AEP and I&M)

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal by the U.S. District Court for the Southern District of Ohio of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

In 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims and remanding the case for further proceedings.

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional $7.5 million to citizens' groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the $7.5 million payment was shared between AEGCo and I&M based on the joint ownership agreement. The district court entered a stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. See "Modification of the New Source Review Litigation Consent Decree" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management cannot determine a range of potential losses that is reasonably possible of occurring.

Patent Infringement Complaint (Applies to AEP, AEP Texas and SWEPCo)

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and the denial to those claims have been appealed to the AEP System Retirement Plan Appeal Committee. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

6. ACQUISITIONS

The disclosures in this note apply to AEP unless indicated otherwise.

Sempra Renewables LLC (Generation & Marketing Segment)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million.

Upon closing of the purchase, Sempra Renewables LLC was legally renamed AEP Wind Holdings LLC. AEP Wind Holdings LLC develops, owns and operates, or holds interests in, wind generation facilities in the United States. The operating wind generation portfolio includes seven wind farms. Five wind farms are jointly-owned with BP Wind Energy, and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. All seven wind farms have long-term PPAs for 100% of their energy production.

Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of March 31, 2020, the maximum potential amount of future payments associated with these guarantees was $175 million, with the last guarantee expiring in December 2037. The non-contingent liability recorded associated with these guarantees was $33 million, with an additional $1 million expected credit loss liability for the contingent portion of the guarantees. Management considered historical losses, economic conditions, and reasonable and supportable forecasts in the calculation of the expected credit loss. As the joint ventures generate cash flows through PPAs, the measurement of the contingent portion of the guarantee liability is based upon assessments of the credit quality and default probabilities of the respective PPA counterparties.

7. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

AEP

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 28.0	$ 23.9	$ 2.5	$ 2.4
Interest Cost	42.0	51.1	9.9	12.6
Expected Return on Plan Assets	(66.2)	(74.0)	(23.9)	(23.4)
Amortization of Prior Service Credit	—	—	(17.4)	(17.3)
Amortization of Net Actuarial Loss	23.4	14.4	1.5	5.5
Net Periodic Benefit Cost (Credit)	$ 27.2	$ 15.4	$ (27.4)	$ (20.2)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.6	$ 2.1	$ 0.2	$ 0.2
Interest Cost	3.5	4.4	0.8	1.0
Expected Return on Plan Assets	(5.7)	(6.4)	(2.0)	(2.0)
Amortization of Prior Service Credit	—	—	(1.4)	(1.5)
Amortization of Net Actuarial Loss	1.9	1.2	0.1	0.5
Net Periodic Benefit Cost (Credit)	$ 2.3	$ 1.3	$ (2.3)	$ (1.8)

APCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.6	$ 2.4	$ 0.3	$ 0.3
Interest Cost	5.1	6.3	1.6	2.2
Expected Return on Plan Assets	(8.4)	(9.4)	(3.6)	(3.7)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.8	1.8	0.2	0.9
Net Periodic Benefit Cost (Credit)	$ 2.1	$ 1.1	$ (4.0)	$ (2.8)

I&M

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 3.9	$ 3.4	$ 0.3	$ 0.3
Interest Cost	4.9	6.0	1.2	1.5
Expected Return on Plan Assets	(8.3)	(9.2)	(2.9)	(2.8)
Amortization of Prior Service Credit	—	—	(2.4)	(2.4)
Amortization of Net Actuarial Loss	2.7	1.6	0.2	0.7
Net Periodic Benefit Cost (Credit)	$ 3.2	$ 1.8	$ (3.6)	$ (2.7)

OPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.4	$ 2.0	$ 0.2	$ 0.2
Interest Cost	3.9	4.7	1.0	1.4
Expected Return on Plan Assets	(6.6)	(7.3)	(2.6)	(2.7)
Amortization of Prior Service Credit	—	—	(1.8)	(1.7)
Amortization of Net Actuarial Loss	2.1	1.3	0.2	0.6
Net Periodic Benefit Cost (Credit)	$ 1.8	$ 0.7	$ (3.0)	$ (2.2)

PSO

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 1.8	$ 1.6	$ 0.2	$ 0.2
Interest Cost	2.1	2.6	0.5	0.7
Expected Return on Plan Assets	(3.6)	(4.1)	(1.3)	(1.3)
Amortization of Prior Service Credit	—	—	(1.1)	(1.1)
Amortization of Net Actuarial Loss	1.2	0.8	0.1	0.3
Net Periodic Benefit Cost (Credit)	$ 1.5	$ 0.9	$ (1.6)	$ (1.2)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.5	$ 2.1	$ 0.2	$ 0.2
Interest Cost	2.5	3.1	0.6	0.8
Expected Return on Plan Assets	(3.9)	(4.4)	(1.5)	(1.5)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.4	0.9	0.1	0.3
Net Periodic Benefit Cost (Credit)	$ 2.5	$ 1.7	$ (1.9)	$ (1.5)

8. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved ROEs.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved ROEs.

Generation & Marketing

- Competitive generation in ERCOT and PJM.
- Contracted renewable energy investments and management services.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.

The remainder of AEP's activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense, income tax expense and other nonallocated costs.

The tables below present AEP's reportable segment income statement information for the three months ended March 31, 2020 and 2019 and reportable segment balance sheet information as of March 31, 2020 and December 31, 2019.

	Three Months Ended March 31, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from							
External Customers	$ 2,193 0	$ 1,075.2	$ 73.1	$ 408.4	$ (2.2)	$ —	$ 3,747.5
Other Operating Segments	33 7	31 7	237 1	30 2	22.1	(354 8)	—
Total Revenues	$ 2,226.7	$ 1,106 9	$ 310.2	$ 438 6	$ 19.9	$ (354 8)	$ 3,747 5
Net Income (Loss)	$ 246.3	$ 116 2	$ 141.6	$ 30.5	$ (35.3)	$ —	$ 499.3

	Three Months Ended March 31, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from							
External Customers	$ 2,372.3	$ 1,179.8	$ 61.2	$ 439.7	$ 3.8	$ —	$ 4,056.8
Other Operating Segments	31 0	42 2	195 2	42 1	21 7	(332 2)	—
Total Revenues	$ 2,403.3	$ 1,222.0	$ 256.4	$ 481.8	$ 25.5	$ (332 2)	$ 4,056.8
Net Income (Loss)	$ 303.6	$ 156 5	$ 125 2	$ 39.2	$ (50.4)	$ —	$ 574.1

	March 31, 2020						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other (a)**	**Reconciling Adjustments**	**Consolidated**
				(in millions)			
Total Property, Plant and Equipment	$ 47,764.3	$ 20,182.8	$ 10,662.9	$ 1,753.2	$ 408.3	$ (354.5) (b)	$ 80,417.0
Accumulated Depreciation and Amortization	14,821.8	3,964.6	464.0	116.9	187.3	(186.5) (b)	19,368.1
Total Property Plant and Equipment - Net	$ 32,942.5	$ 16,218.2	$ 10,198.9	$ 1,636.3	$ 221.0	$ (168.0) (b)	$ 61,048.9
Total Assets	$ 41,020.5	$ 18,892.5	$ 11,484.8	$ 3,216.4	$ 7,033.6 (c)	$ (3,923.8) (b) (d)	$ 77,724.0
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	$ —
Nonaffiliated	1,316.3	289.0	—	—	504.4 (e)	—	2,109.7
Long-term Debt:							
Affiliated	39.0	—	—	—	—	(39.0)	—
Nonaffiliated	11,641.0	6,585.5	3,600.3	—	3,956.2 (e)	—	25,783.0
Total Long-term Debt	$ 13,016.3	$ 6,874.5	$ 3,600.3	$ —	$ 4,460.6	$ (59.0)	$ 27,892.7

	December 31, 2019						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other (a)**	**Reconciling Adjustments**	**Consolidated**
				(in millions)			
Total Property, Plant and Equipment	$ 47,323.7	$ 19,773.3	$ 10,334.0	$ 1,650.8	$ 418.4	$ (354.5) (b)	$ 79,145.7
Accumulated Depreciation and Amortization	14,580.4	3,911.2	418.9	99.0	184.5	(186.4) (b)	19,007.6
Total Property Plant and Equipment - Net	$ 32,743.3	$ 15,862.1	$ 9,915.1	$ 1,551.8	$ 233.9	$ (168.1) (b)	$ 60,138.1
Total Assets	$ 41,228.8	$ 18,757.5	$ 11,143.5	$ 3,123.8	$ 5,440.0 (c)	$ (3,801.3) (b) (d)	$ 75,892.3
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	$ —
Nonaffiliated	704.7	392.2	—	—	501.8 (e)	—	1,598.7
Long-term Debt:							
Affiliated	39.0	—	—	—	—	(39.0)	—
Nonaffiliated	12,162.0	6,248.1	3,593.8	—	3,122.9 (e)	—	25,126.8
Total Long-term Debt	$ 12,925.7	$ 6,640.3	$ 3,593.8	$ —	$ 3,624.7	$ (59.0)	$ 26,725.5

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Includes eliminations due to an intercompany finance lease
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.
(e) Amounts reflect the impact of fair value hedge accounting See "Accounting for Fair Value Hedging Strategies" section of Note 10 for additional information

Registrant Subsidiaries' Reportable Segments (Applies to all Registrant Subsidiaries except AEPTCo)

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an integrated electricity transmission and distribution business for AEP Texas and OPCo. Other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities. The seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting." The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTOs in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

AEPTCo's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. The State Transcos operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the three months ended March 31, 2020 and 2019 and reportable segment balance sheet information as of March 31, 2020 and December 31, 2019.

	Three Months Ended March 31, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from				
External Customers	$ 61.3	$ —	$ —	$ 61.3
Sales to AEP Affiliates	233 7	—	—	233 7
Other Revenues	0.6	—	—	0.6
Total Revenues	$ 295 6	$ —	$ —	$ 295 6
Interest Income	$ 0 2	$ 34 0	$ (33 4) (a)	$ 0 8
Interest Expense	29 6	33.4	(33 4) (a)	29 6
Income Tax Expense	31 8	—	—	31 8
Net Income	$ 117 3	$ 0 5 (b)	$ —	$ 117.8

	Three Months Ended March 31, 2019			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from				
External Customers	$ 50.3	$ —	$ —	$ 50.3
Sales to AEP Affiliates	193 2	—	—	193 2
Total Revenues	$ 243.5	$ —	$ —	$ 243.5
Interest Income	$ 0.2	$ 28 4	$ (27.9) (a)	$ 0.7
Interest Expense	21 7	27 9	(27 9) (a)	21 7
Income Tax Expense	27.6	—	—	27.6
Net Income	$ 104 2	$ 0.1 (b)	$ —	$ 104.3

	March 31, 2020							
	State Transcos		AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated	
	(in millions)							
Total Transmission Property	$	10,221.2	$	—	$	—	$	10,221 2
Accumulated Depreciation and Amortization		445 8		—		—		445 8
Total Transmission Property – Net	$	9,775.4	$	—	$	—	$	9,775.4
Notes Receivable - Affiliated	$	—	$	3,427.8	$	(3,427.8) (c)	$	—
Total Assets	$	10,150.9	$	3,562.7 (d)	$	(3,513.7) (e)	$	10,199.9
Total Long-term Debt	$	3,465.0	$	3,427.8	$	(3,465.0) (c)	$	3,427 8

	December 31, 2019							
	State Transcos		AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated	
	(in millions)							
Total Transmission Property	$	9,893.2	$	—	$	—	$	9,893 2
Accumulated Depreciation and Amortization		402.3		—		—		402 3
Total Transmission Property – Net	$	9,490 9	$	—	$	—	$	9,490.9
Notes Receivable - Affiliated	$	—	$	3,427 3	$	(3,427.3) (c)	$	—
Total Assets	$	9,865.0	$	3,519.1 (d)	$	(3,493.3) (e)	$	9,890 8
Total Long-term Debt	$	3,465.0	$	3,427 3	$	(3,465.0) (c)	$	3,427.3

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement
(b) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos
(c) Elimination of intercompany debt
(d) Includes the elimination of AEPTCo Parent's investments in State Transcos
(e) Primarily relates to the elimination of Notes Receivable from the State Transcos

9. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise. For the periods presented, AEPTCo did not have any derivative and hedging activity.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments
March 31, 2020

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity.								
Power	MWhs	305.4	—	38.7	18.5	3.2	5.9	1.7
Natural Gas	MMBtus	42.3	—	—	—	—	—	10.7
Heating Oil and Gasoline	Gallons	5.0	1.3	0.8	0.5	1.0	0.5	0.7
Interest Rate	USD	$ 137 1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 650 0	$ —	$ 150.0	$ —	$ —	$ —	$ —

December 31, 2019

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	365.9	—	61.0	26.8	7.1	14.9	4.4
Natural Gas	MMBtus	40.7	—	—	—	—	—	11.6
Heating Oil and Gasoline	Gallons	6.9	1.8	1.1	0.6	1.4	0.7	0.9
Interest Rate	USD	$ 140.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 625.0	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

Parent enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating-rate. Provided specific criteria are met, these interest rate derivatives may be designated as fair value hedges.

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. AEP netted cash collateral received from third-parties against short-term and long-term risk management assets in the amounts of $0 and $5 million as of March 31, 2020 and December 31, 2019, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $76 million and $39 million as of March 31, 2020 and December 31, 2019, respectively. APCo netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $5 million and $1 million as of March 31, 2020 and December 31, 2019, respectively. The netted cash collateral from third-parties against short-term and long-term risk management assets and netted cash collateral paid to third-parties against short-term and long-term risk management liabilities were immaterial for the other Registrant Subsidiaries as of March 31, 2020 and December 31, 2019.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 412.7	$ 13.5	$ 4.6	$ 430 8	$ (300 4)	$ 130.4
Long-term Risk Management Assets	331 6	13 5	52 7	397 8	(74 1)	323 7
Total Assets	744.3	27.0	57.3	828.6	(374.5)	454.1
Current Risk Management Liabilities	401.7	103 2	5.3	510.2	(353.4)	156.8
Long-term Risk Management Liabilities	305 9	82 9	—	388 8	(96 9)	291 9
Total Liabilities	707.6	186.1	5.3	899.0	(450.3)	448.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 36.7	$ (159.1)	$ 52.0	$ (70.4)	$ 75.8	$ 5.4

December 31, 2019

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 513.9	$ 11.5	$ 6 5	$ 531.9	$ (359.1)	$ 172.8
Long-term Risk Management Assets	290 8	11 0	12 6	314 4	(47 8)	266 6
Total Assets	804.7	22.5	19.1	846 3	(406.9)	439.4
Current Risk Management Liabilities	424.5	72.3	—	496.8	(382.5)	114.3
Long-term Risk Management Liabilities	244 5	75 7	—	320 2	(58 4)	261 8
Total Liabilities	669.0	148.0	—	817 0	(440.9)	376.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 135.7	$ (125.5)	$ 19.1	$ 29 3	$ 34.0	$ 63.3

AEP Texas

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	1 2	(1.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	1 2	(1 2)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1.2)	$ 1.2	$ —

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ —	$ —	$ —

APCo

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Hedging Contracts – Interest Rate (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)	
Current Risk Management Assets	$ 71.1	$ 0.3	$ (53 3)	$ 18 1
Long-term Risk Management Assets	3 5	—	(3 4)	0.1
Total Assets	74.6	0 3	(56.7)	18.2
Current Risk Management Liabilities	68.3	5 3	(58 6)	15.0
Long-term Risk Management Liabilities	3 5	—	(3 4)	0 1
Total Liabilities	71 8	5.3	(62.0)	15.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2 8	$ (5.0)	$ 5.3	$ 3.1

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 124.4	$ (85.0)	$ 39 4
Long-term Risk Management Assets	0 9	(0 8)	0 1

Total Assets	125.3	(85.8)	39.5
Current Risk Management Liabilities	86.2	(84.3)	1.9
Long-term Risk Management Liabilities	0 7	(0 7)	—
Total Liabilities	86.9	(85.0)	1.9
Total MTM Derivative Contract Net Assets (Liabilities)	$ 38.4	$ (0.8)	$ 37.6

I&M

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 42.3	$ (35.6)	$ 6 7
Long-term Risk Management Assets	2 1	(2 0)	0 1
Total Assets	44.4	(37 6)	6.8
Current Risk Management Liabilities	38.3	(36 6)	1.7
Long-term Risk Management Liabilities	2 1	(2 0)	0 1
Total Liabilities	40.4	(38.6)	1 8
Total MTM Derivative Contract Net Assets	$ 4 0	$ 1 0	$ 5.0

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 66.9	$ (57 1)	$ 9.8
Long-term Risk Management Assets	0 5	(0 4)	0 1
Total Assets	67.4	(57 5)	9 9
Current Risk Management Liabilities	55.2	(54.7)	0 5
Long-term Risk Management Liabilities	0 4	(0 4)	—
Total Liabilities	55 6	(55.1)	0.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 11.8	$ (2.4)	$ 9.4

OPCo

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	9.6	(0.9)	8.7
Long-term Risk Management Liabilities	112 2	—	112 2
Total Liabilities	121.8	(0.9)	120.9
Total MTM Derivative Contract Net Assets (Liabilities)	$ (121.8)	$ 0.9	$ (120 9)

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—

Current Risk Management Liabilities	7.3	—	7.3
Long-term Risk Management Liabilities	96 3	—	96 3
Total Liabilities	103.6	—	103.6
Total MTM Derivative Contract Net Liabilities	$ (103.6)	$ —	$ (103 6)

PSO

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 6.7	$ (0.3)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6 7	(0.3)	6.4
Current Risk Management Liabilities	0 9	(0.8)	0.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0 9	(0.8)	0 1
Total MTM Derivative Contract Net Assets	$ 5.8	$ 0 5	$ 6.3

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 16.3	$ (0.5)	$ 15.8
Long-term Risk Management Assets	—	—	—
Total Assets	16 3	(0.5)	15.8
Current Risk Management Liabilities	0.5	(0 5)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0 5)	—
Total MTM Derivative Contract Net Assets	$ 15 8	$ —	$ 15.8

SWEPCo

Fair Value of Derivative Instruments
March 31, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 2.7	$ (0.1)	$ 2.6
Long-term Risk Management Assets	—	—	—
Total Assets	2.7	(0.1)	2.6
Current Risk Management Liabilities	2.9	(0 7)	2.2
Long-term Risk Management Liabilities	2 9	—	2 9
Total Liabilities	5 8	(0.7)	5.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ (3.1)	$ 0.6	$ (2 5)

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 6.5	$ (0.1)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.5	(0.1)	6 4

Current Risk Management Liabilities	2 0	(0.1)	1 9
Long-term Risk Management Liabilities	3 1	—	3 1
Total Liabilities	5 1	(0.1)	5 0
Total MTM Derivative Contract Net Assets	$ 1.4	$ —	$ 1.4

(a) Derivative instruments within these categories are reported gross These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging "

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging "

(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts
Three Months Ended March 31, 2020

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0 4	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(10 3)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0 2	0.1	—	—	—
Purchased Electricity for Resale	0 1	—	0 1	—	—	—	—
Other Operation	(0 2)	(0.1)	—	—	(0.1)	—	—
Maintenance	(0 2)	(0 1)	(0 1)	—	—	—	—
Regulatory Assets (a)	(33.9)	(1.2)	(8.9)	(0.7)	(18 4)	(0.5)	(2 0)
Regulatory Liabilities (a)	11 2	—	(7 3)	3 2	3 5	8 1	3 3
Total Gain (Loss) on Risk Management Contracts	$ (32.9)	$ (1.4)	$ (16.0)	$ 2.6	$ (15 0)	$ 7.6	$ 1.3

Three Months Ended March 31, 2019

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.3	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	2 7	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.1)	0.3	—	—	0.1
Purchased Electricity for Resale	1 4	—	—	—	—	—	—
Other Operation	(0 4)	(0 1)	(0.1)	—	(0.1)	—	—
Maintenance	(0 5)	(0 1)	—	—	(0 1)	—	(0 1)
Regulatory Assets (a)	(6 4)	0.6	(2.1)	0.3	(8 9)	0.5	(0.1)
Regulatory Liabilities (a)	(22 0)	—	(31 7)	6.6	—	6 2	4 7
Total Gain (Loss) on Risk Management Contracts	$ (24 9)	$ 0.4	$ (34.0)	$ 7.2	$ (9.1)	$ 6.7	$ 4.6

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts net income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income.

The following table shows the impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	March 31, 2020	December 31, 2019	March 31, 2020	December 31, 2019
	(in millions)			
Long-term Debt (a)	$ (553 4)	$ (510 8)	$ (57 0)	$ (14 5)

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively

The pretax effects of fair value hedge accounting on income were as follows:

	Three Months Ended March 31,	
	2020	2019
	(in millions)	
Gain (Loss) on Interest Rate Contracts		
Gain on Fair Value Hedging Instruments (a)	$ 42 5	$ 11 1
Loss on Fair Value Portion of Long-term Debt (a)	(42 5)	(11 1)

(a) Gain (Loss) is included in Interest Expense on the statements of income

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects net income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2020 and 2019, AEP applied cash flow hedging to outstanding power derivatives. During the three months ended March 31, 2020 and 2019, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2020, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three months ended March 31, 2019, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3 - Comprehensive Income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	March 31, 2020		December 31, 2019	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (128 5)	$ (53 5)	$ (103 5)	$ (11 5)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(73 2)	(4 3)	(51 7)	(2 1)

As of March 31, 2020 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 132 months and 129 months for commodity and interest rate hedges, respectively.

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets

	March 31, 2020		December 31, 2019	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (3 1)	$ (1 1)	$ (3.4)	$ (1.1)
APCo	(3 3)	1 1	0 9	0 9
I&M	(9 5)	(1.6)	(9 9)	(1.6)
PSO	0 9	0 9	1 1	1 0
SWEPCo	(1.4)	(1.5)	(1.8)	(1.5)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of March 31, 2020 and December 31, 2019, respectively.

Cross-Default Triggers (Applies to AEP, APCo, I&M and SWEPCo)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	March 31, 2020		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 310.4	$ 1.6	$ 282.9
APCo	2 2	—	0.2
I&M	1.3	—	0.1
SWEPCo	5.5	—	5.5

	December 31, 2019		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 267.3	$ 3.7	$ 246.7
APCo	2.3	—	0.4
I&M	1.3	—	0.2
SWEPCo	5.1	—	5.1

10. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Fair Value Measurements of Long-term Debt (Applies to all Registrants)

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value of AEP's Equity Units (Level 1) are valued based on publicly traded securities issued by AEP.

The book values and fair values of Long-term Debt are summarized in the following table:

	March 31, 2020		December 31, 2019	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
		(in millions)		
AEP (a)	$ 27,892.7	$ 29,776.6	$ 26,725.5	$ 30,172.0
AEP Texas	4,445.4	4,637.3	4,558.4	4,981.5
AEPTCo	3,427.8	3,680.7	3,427.3	3,868.0
APCo	4,352.4	4,959.0	4,363.8	5,253.1
I&M	3,028.0	3,318.2	3,050.2	3,453.8
OPCo	2,429.1	2,795.3	2,082.0	2,554.3
PSO	1,386.3	1,553.9	1,386.2	1,603.3
SWEPCo	2,654.4	2,776.5	2,655.6	2,927.9

(a) The fair value amount includes debt related to AEP's Equity Units issued in March 2019 and has a fair value of $777 million and $871 million as of March 31, 2020 and December 31, 2019, respectively. See "Equity Units" section of Note 12 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments:

	March 31, 2020			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 151.9	$ —	$ —	$ 151.9
Fixed Income Securities – Mutual Funds (b)	118.6	0.4	—	119.0
Equity Securities – Mutual Funds	19.3	11.2	—	30.5
Total Other Temporary Investments	$ 289.8	$ 11.6	$ —	$ 301.4

	December 31, 2019			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 214.7	$ —	$ —	$ 214.7
Fixed Income Securities – Mutual Funds (b)	123.2	0.1	—	123.3
Equity Securities – Mutual Funds	29.2	21.3	—	50.5
Total Other Temporary Investments	$ 367.1	$ 21.4	$ —	$ 388.5

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Three Months Ended March 31,	
	2020	2019
	(in millions)	
Proceeds from Investment Sales	$ 23.2	$ —
Purchases of Investments	6.7	0.1
Gross Realized Gains on Investment Sales	2.0	—
Gross Realized Losses on Investment Sales	0.1	—

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Available-for-sale classification only applies to investment in debt securities in accordance with ASU 2016-01. Additionally, ASU 2016-01 requires changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund securities.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI.

The following is a summary of nuclear trust fund investments:

	March 31, 2020			December 31, 2019		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 46 9	$ —	$ —	$ 15.3	$ —	$ —
Fixed Income Securities						
United States Government	1,026 1	121.4	(5 6)	1,112 5	55.5	(6.1)
Corporate Debt	62 7	6 0	(1 6)	72 4	5 3	(1 6)
State and Local Government	149.7	1.5	(0.2)	7.6	0.7	(0.2)
Subtotal Fixed Income Securities	1,238 5	128.9	(7 4)	1,192 5	61 5	(7 9)
Equity Securities - Domestic (a)	1,393 8	777.6	—	1,767.9	1,144.4	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,679 2	$ 906 5	$ (7 4)	$ 2,975 7	$ 1,205 9	$ (7 9)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $801 million and $1 1 billion and unrealized losses of $23 million and $5 million as of March 31, 2020 and December 31, 2019, respectively

The following table provides the securities activity within the decommissioning and SNF trusts:

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
	(in millions)	
Proceeds from Investment Sales	$ 612.4	$ 111.9
Purchases of Investments	626.0	130.3
Gross Realized Gains on Investment Sales	10.9	12.3
Gross Realized Losses on Investment Sales	17.0	13 8

The base cost of fixed income securities was $1.1 billion and $1.1 billion as of March 31, 2020 and December 31, 2019, respectively. The base cost of equity securities was $616 million and $623 million as of March 31, 2020 and December 31, 2019, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2020 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 238.9
After 1 year through 5 years	404.5
After 5 years through 10 years	282.5
After 10 years	312.6
Total	$ 1,238.5

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 128.1	$ —	$ —	$ 23.8	$ 151.9
Fixed Income Securities – Mutual Funds	119 0	—	—	—	119 0
Equity Securities – Mutual Funds (b)	30.5	—	—	—	30.5
Total Other Temporary Investments	277.6	—	—	23.8	301.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.7	369.8	346.1	(340.5)	379.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	18.7	4.2	(5.2)	17.7
Interest Rate Hedges	—	0 3	—	—	0.3
Fair Value Hedges	—	57.0	—	—	57.0
Total Risk Management Assets	3 7	445 8	350.3	(345.7)	454.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	37.0	—	—	9.9	46.9
Fixed Income Securities:					
United States Government	—	1,026.1	—	—	1,026.1
Corporate Debt	—	62.7	—	—	62.7
State and Local Government	—	149.7	—	—	149.7
Subtotal Fixed Income Securities	—	1,238.5	—	—	1,238 5
Equity Securities – Domestic (b)	1,393.8	—	—	—	1,393.8
Total Spent Nuclear Fuel and Decommissioning Trusts	1,430.8	1,238.5	—	9.9	2,679.2
Total Assets	$ 1,712.1	$ 1,684.3	$ 350.3	$ (312 0)	$ 3,434 7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 4.9	$ 410.1	$ 267.9	$ (416.3)	$ 266.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	142.1	39.9	(5.2)	176.8
Interest Rate Hedges	—	5.3	—	—	5.3
Total Risk Management Liabilities	$ 4.9	$ 557.5	$ 307.8	$ (421.5)	$ 448.7

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 197.6	$ —	$ —	$ 17.1	$ 214.7
Fixed Income Securities – Mutual Funds	123.3	—	—	—	123.3
Equity Securities – Mutual Funds (b)	50.5	—	—	—	50.5
Total Other Temporary Investments	371.4	—	—	17.1	388.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	4.0	440.1	369.2	(404.5)	408.8
Cash Flow Hedges					
Commodity Hedges (c)	—	15.0	3.2	(6.7)	11.5
Interest Rate Hedges	—	4 6	—	—	4.6
Fair Value Hedges	—	14.5	—	—	14.5
Total Risk Management Assets	4.0	474.2	372 4	(411.2)	439.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities.					
United States Government	—	1,112.5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7.6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192 5	—	—	1,192 5
Equity Securities – Domestic (b)	1,767.9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 2,150.0	$ 1,666.7	$ 372.4	$ (385.5)	$ 3,803.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 3.8	$ 450.0	$ 224.0	$ (438.8)	$ 239.0
Cash Flow Hedges:					
Commodity Hedges (c)	—	105.3	38.5	(6.7)	137.1
Total Risk Management Liabilities	$ 3.8	$ 555.3	$ 262 5	$ (445.5)	$ 376.1

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Assets:					
Restricted Cash for Securitized Funding	$ 100.1	$ —	$ —	$ —	$ 100.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 1 2	$ —	$ (1.2)	$ —

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Assets:					
Restricted Cash for Securitized Funding	$ 154.7	$ —	$ —	$ —	$ 154.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Assets:					
Restricted Cash for Securitized Funding	$ 15.7	$ —	$ —	$ —	$ 15.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	55.0	17 1	(54.2)	17.9
Cash Flow Hedges:					
Interest Rate Hedges	—	0.3	—	—	0 3
Total Risk Management Assets	—	55.3	17.1	(54.2)	18.2
Total Assets	$ 15.7	$ 55.3	$ 17.1	$ (54.2)	$ 33.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 58.8	$ 10.5	$ (59.5)	$ 9.8
Cash Flow Hedges:					
Interest Rate Hedges	—	5.3	—	—	5.3
Total Risk Management Liabilities	$ —	$ 64.1	$ 10.5	$ (59.5)	$ 15.1

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Assets:					
Restricted Cash for Securitized Funding	$ 23.5	$ —	$ —	$ —	$ 23.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	84.6	40.5	(85.6)	39.5
Total Assets	$ 23.5	$ 84.6	$ 40.5	$ (85.6)	$ 63.0
Liabilities:					

Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 84.0	$ 2.8	$ (84.9)	$ 1.9

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 38.1	$ 4.9	$ (36.2)	$ 6.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	37.0	—	—	9.9	46.9
Fixed Income Securities:					
United States Government	—	1,026.1	—	—	1,026.1
Corporate Debt	—	62.7	—	—	62.7
State and Local Government	—	149.7	—	—	149.7
Subtotal Fixed Income Securities	—	1,238.5	—	—	1,238.5
Equity Securities - Domestic (b)	1,393.8	—	—	—	1,393.8
Total Spent Nuclear Fuel and Decommissioning Trusts	1,430.8	1,238.5	—	9.9	2,679.2
Total Assets	$ 1,430.8	$ 1,276.6	$ 4.9	$ (26.3)	$ 2,686.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 36.2	$ 2.8	$ (37 2)	$ 1.8

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 59.5	$ 8.0	$ (57.6)	$ 9.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities:					
United States Government	—	1,112 5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7 6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192.5	—	—	1,192.5
Equity Securities - Domestic (b)	1,767 9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 1,774.6	$ 1,252.0	$ 8.0	$ (49.0)	$ 2,985.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 53.4	$ 2 2	$ (55.1)	$ 0.5

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.9	$ 120.9	$ (0 9)	$ 120.9

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 103.6	$ —	$ 103 6

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 6.7	$ (0.3)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ 0.4	$ (0.8)	$ 0 1

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 16.3	$ (0.5)	$ 15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.5	$ (0 5)	$ —

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 2.7	$ (0.1)	$ 2.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0 6	$ 5.2	$ (0.7)	$ 5.1

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 6.5	$ (0.1)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 5 1	$ (0.1)	$ 5 0

(a) Amounts ın "Other" column prımarily represent cash deposits in bank accounts with financıal ınstitutıons or third-parties Level 1 and Level 2 amounts primarily represent investments ın money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts ın "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guıdance for "Derivatives and Hedging."
(d) The March 31, 2020 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilıties), is as follows. Level 1 matures $(1) million in periods 2021-2023; Level 2 matures $(30) million in 2020, $(9) million ın periods 2021-2023 and $(1) million in periods 2024-2025; Level 3 matures $37 million in 2020, $36 million in periods 2021-2023, $25 mıllion in periods 2024-2025 and $(20) million ın periods 2026-2032 Risk management commodity contracts are substantially comprised of power contracts.
(e) Amounts ın "Other" column primarily represent accrued interest receıvables from financıal institutıons. Level 1 amounts primarily represent investments in money market funds.
(f) The December 31, 2019 maturity of the net fair value of rısk management contracts prior to cash collateral, assets/(lıabilitıes), is as follows· Level 2 matures $(7) mıllion ın 2020 and $(3) million in periods 2021-2023, Level 3 matures $96 million in 2020, $36 millıon ın periods 2021-2023, $25 million ın periods 2024-2025 and $(12) million ın perıods 2026-2032 Risk management commodity contracts are substantıally comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Three Months Ended March 31, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	0 9	(9.2)	0.2	(0.3)	8.0	1 9
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	10.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(4.1)	—	—	—	—	—
Settlements	(59.2)	(21.9)	(4.0)	2.5	(17.7)	(5.3)
Transfers into Level 3 (d) (e)	(0.5)	—	—	—	—	—
Transfers out of Level 3 (e)	5.3	0.7	0.4	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(20 7)	(0.7)	(0.3)	(19 5)	0.2	(0.5)
Balance as of March 31, 2020	$ 42.5	$ 6.6	$ 2.1	$ (120.9)	$ 6.3	$ (2.5)

Three Months Ended March 31, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(23.0)	(29.0)	—	(0 4)	6.8	3.3
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	8.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(15.8)	—	—	—	—	—
Settlements	(54.5)	(17.8)	(5.1)	1.8	(13.0)	(7.3)
Transfers into Level 3 (d) (e)	0.1	—	—	—	—	—
Transfers out of Level 3 (e)	(1.2)	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(7.2)	(2.9)	1.0	(8.1)	1.1	1.7
Balance as of March 31, 2019	$ 38.1	$ 7.4	$ 4.4	$ (106.1)	$ 4.4	$ —

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

AEP

Significant Unobservable Inputs
March 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 321.2	$ 284.6	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 135.24	$ 29.17
Natural Gas Contracts	—	5.1	Discounted Cash Flow	Forward Market Price (b)	1.37	2.51	2.13
FTRs	29.1	18.1	Discounted Cash Flow	Forward Market Price (a)	(10.12)	4.17	(0.31)
Total	$ 350.3	$ 307.8					

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 296.7	$ 249.3	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 177.30	$ 31.31
Natural Gas Contracts	—	4.9	Discounted Cash Flow	Forward Market Price (b)	1.89	2.51	2.19
FTRs	75.7	8.3	Discounted Cash Flow	Forward Market Price (a)	(8.52)	9.34	0.42
Total	$ 372.4	$ 262.5					

APCo

Significant Unobservable Inputs
March 31, 2020

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Energy Contracts	$ 5.3	$ 2.2	Discounted Cash Flow	Forward Market Price	$ 9.95	$ 42.15	$ 21.81
FTRs	11.8	8.3	Discounted Cash Flow	Forward Market Price	—	3.44	0.42
Total	$ 17.1	$ 10.5					

December 31, 2019

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Energy Contracts	$ 5.7	$ 2.6	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	34.8	0.2	Discounted Cash Flow	Forward Market Price	(0.14)	7.08	1.70
Total	$ 40.5	$ 2.8					

I&M

Significant Unobservable Inputs
March 31, 2020

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Energy Contracts	$ 3.2	$ 1.3	Discounted Cash Flow	Forward Market Price	$ 9.95	$ 42.15	$ 21.81
FTRs	1.7	1.5	Discounted Cash Flow	Forward Market Price	(0.51)	2.77	0.12
Total	$ 4.9	$ 2.8					

December 31, 2019

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Energy Contracts	$ 3.4	$ 1.5	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	4.6	0.7	Discounted Cash Flow	Forward Market Price	(0.75)	4.07	0.74
Total	$ 8.0	$ 2.2					

OPCo

Significant Unobservable Inputs
March 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 120.9	Discounted Cash Flow	Forward Market Price	$ 12.57	$ 42.71	$ 26.31

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 103.6	Discounted Cash Flow	Forward Market Price	$ 29.23	$ 61.43	$ 42.46

PSO

Significant Unobservable Inputs
March 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 6.7	$ 0.4	Discounted Cash Flow	Forward Market Price	$ (7.07)	$ 0.95	$ (2.38)

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 16.3	$ 0.5	Discounted Cash Flow	Forward Market Price	$ (8.52)	$ 0.85	$ (2.31)

SWEPCo

Significant Unobservable Inputs
March 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 5.1	Discounted Cash Flow	Forward Market Price (b)	$ 1.37	$ 2.51	$ 2.13
FTRs	2.7	0.1	Discounted Cash Flow	Forward Market Price (a)	(7.07)	0.95	(2.38)
Total	$ 2.7	$ 5.2					

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 4.9	Discounted Cash Flow	Forward Market Price (b)	$ 1.89	$ 2.51	$ 2.18
FTRs	6.5	0.2	Discounted Cash Flow	Forward Market Price (a)	(8.52)	0.85	(2.31)
Total	$ 6.5	$ 5.1					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of March 31, 2020 and December 31, 2019:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Federal Legislation

In March 2020, the "Coronavirus Aid, Relief, and Economic Security Act" (CARES Act) was signed into law. The CARES Act includes several significant changes to the Internal Revenue Code that will have an impact on the Registrants. The CARES Act includes certain tax relief provisions applicable to the Registrants including a) the immediate refund of the corporate Alternative Minimum Tax credit, b) the ability to carryback net operating losses five years for tax years 2018 through 2020 and c) delayed payment of employer payroll taxes. As of March 31, 2020, AEP, OPCo and APCo have a $20 million, $9 million and $7 million AMT credit refund recorded, respectively, in anticipation of a refund from the U.S. Treasury. AEP was most recently a taxpayer in 2014 and management is currently evaluating the ability to recover cash taxes paid in 2014 under the 5-year net operating loss carryback provision.

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2020 and 2019, adjusted for tax expense associated with certain discrete items. The interim ETR differ from the federal statutory tax rate of 21% primarily due to amortization of Excess ADIT, tax credits and other book/tax differences which are accounted for on a flow-through basis.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended March 31, 2020							
	AEP	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21 0 %
Increase (decrease) due to								
State Income Tax, net of Federal benefit	2.5 %	1.5 %	2.9 %	3.0 %	3 2 %	0.7 %	4 6 %	2.7 %
Tax Reform Excess ADIT Reversal	(9 4)%	(6 2)%	0 4 %	(13 0)%	(19 6)%	(10 2)%	(23 1)%	(94 7)%
Production and Investment Tax Credits	(4.3)%	(0 4)%	— %	— %	(1.9)%	— %	(1.3)%	(0.5)%
Flow Through	0 5 %	0 1 %	0 5 %	1 5 %	0 2 %	1 0 %	0 6 %	(1 0)%
AFUDC Equity	(1.4)%	(2.6)%	(2.6)%	(1.0)%	(1.1)%	(1.0)%	(0.7)%	(0.4)%
Parent Company Loss Benefit	— %	(0 2)%	(0 9)%	(3 3)%	(3 9)%	(0 1)%	(2 2)%	(2 4)%
Discrete Tax Adjustments	— %	— %	— %	— %	2.7 %	— %	— %	— %
Other	(0 4)%	0 3 %	— %	0 1 %	(0 2)%	— %	0 1 %	7 2 %
Effective Income Tax Rate	8.5 %	13 5 %	21 3 %	8 3 %	0.4 %	11 4 %	(1.0)%	(68.1)%

	Three Months Ended March 31, 2019							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21 0 %	21.0 %	21 0 %	21.0 %
Increase (decrease) due to								
State Income Tax, net of Federal benefit	2.1 %	1.5 %	2.9 %	3.4 %	2.0 %	0 9 %	4 6 %	0.2 %
Tax Reform Excess ADIT Reversal	(13 6)%	(7 6)%	0 4 %	(42 2)%	(17 4)%	(7 6)%	(21 9)%	(17 0)%
Production and Investment Tax Credits	(2 2)%	(1.0)%	— %	— %	(2.0)%	— %	(1.7)%	(0.8)%
Flow Through	(0.2)%	0.3 %	0 2 %	(0 9)%	(2 4)%	0 7 %	0 6 %	(0 9)%
AFUDC Equity	(1.4)%	(1.6)%	(2 5)%	(1.0)%	(1.9)%	(0.7)%	(0.4)%	(1.1)%
Parent Company Loss	— %	(2 3)%	(1 0)%	(2 4)%	(1 8)%	(1 1)%	(1 8)%	(0 5)%
Discrete Tax Adjustments	1 7 %	— %	— %	0.4 %	— %	— %	— %	— %
Other	(0 2)%	0 1 %	(0 1)%	(0 3)%	(0 3)%	0.2 %	0 2 %	1 5 %
Effective Income Tax Rate	7 2 %	10.4 %	20 9 %	(22.0)%	(2 8)%	13.4 %	0.6 %	2.4 %

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

12. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants, unless indicated otherwise.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	March 31, 2020	December 31, 2019
	(in millions)	
Senior Unsecured Notes	$ 22,515.8	$ 21,180.7
Pollution Control Bonds	1,999 2	1,998.8
Notes Payable	209.4	234.3
Securitization Bonds	899.1	1,025.1
Spent Nuclear Fuel Obligation (a)	280.9	279.8
Junior Subordinated Notes (b)	788.6	787.8
Other Long-term Debt	1,199.7	1,219.0
Total Long-term Debt Outstanding	27,892.7	26,725.5
Long-term Debt Due Within One Year	2,109.7	1,598.7
Long-term Debt	$ 25,783.0	$ 25,126.8

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983 Trust fund assets related to this obligation were $324 million and $323 million as of March 31, 2020 and December 31, 2019, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2020 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEP	Senior Unsecured Notes	$ 400.0	2.30	2030
AEP	Senior Unsecured Notes	400 0	3.25	2050
OPCo	Senior Unsecured Notes	350.0	2.60	2030
Non-Registrant:				
KPCo	Other Long-term Debt	125.0	Variable	2022
Transource Energy	Other Long-term Debt	5.0	Variable	2023
Transource Energy	Senior Unsecured Notes	150.0	2.75	2050
Total Issuances		$ 1,430.0		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.