Ohio Valley Electric Corporation and Subsidiary Company

Consolidated Financial Statements as of and for the Years Ended December 31, 2019 and 2018, and Independent Auditors' Report

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Ohio Valley Electric Corporation

We have audited the accompanying consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of income, retained earnings, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Companies' preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Companies as of December 31, 2019 and 2018, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

April 17, 2020

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 2,793,490,793	$ 2,785,266,305
Less—accumulated provisions for depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	1,242,919,563	1,296,155,522
CURRENT ASSETS:		
Cash and cash equivalents	32,241,171	47,523,556
Accounts receivable	74,486,689	64,278,896
Fuel in storage	61,351,858	33,474,186
Emission allowances	291,681	298,355
Materials and supplies	40,931,063	40,634,643
Income taxes receivable	2,307,853	4,690,064
Property taxes applicable to future years	3,150,000	3,062,500
Prepaid expenses and other	2,817,715	2,175,905
Total current assets	217,578,030	196,138,105
REGULATORY ASSETS:		
Unrecognized postemployment benefits	5,201,536	4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	5,902,867
Total regulatory assets	37,371,844	43,945,148
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	688,643	156,683
Long-term investments	240,739,279	181,271,533
Income taxes receivable	2,307,341	4,614,683
Other	2,510,636	1,245,637
Total deferred charges and other	246,245,899	187,288,536
TOTAL	$ 1,744,115,336	$ 1,723,527,311

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2019 and 2018	$ 10,000,000	$ 10,000,000
Long-term debt	1,119,568,409	1,110,069,775
Line of credit borrowings	80,000,000	-
Retained earnings	17,294,023	14,238,732
Total capitalization	1,226,862,432	1,134,308,507
CURRENT LIABILITIES:		
Current portion of long-term debt	141,387,803	179,670,116
Line of credit borrowings	-	85,000,000
Accounts payable	34,871,926	41,313,387
Accrued other taxes	10,527,047	10,725,765
Regulatory liabilities	7,677,404	7,657,791
Accrued interest and other	27,532,934	20,663,191
Total current liabilities	221,997,114	345,030,250
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	-
Total regulatory liabilities	189,539,856	135,230,486
OTHER LIABILITIES:		
Pension liability	32,170,308	33,894,325
Asset retirement obligations	63,487,038	60,246,682
Postretirement benefits obligation	4,242,848	10,186,597
Postemployment benefits obligation	5,201,536	4,147,956
Other non-current liabilities	614,204	482,508
Total other liabilities	105,715,934	108,958,068
TOTAL	$ 1,744,115,336	$ 1,723,527,311

See notes to consolidated financial statements. (Concluded)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 4,641,167	$ 7,605,922
Sponsoring Companies	606,993,408	608,233,419
Other	3,033,066	-
Total revenues from contracts with customers	614,667,641	615,839,341
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	274,843,402	277,368,623
Purchased power	3,735,333	6,863,294
Other operation	91,611,162	86,302,869
Maintenance	87,208,116	86,305,942
Depreciation	88,825,066	54,190,596
Taxes—other than income taxes	11,330,963	12,164,929
Income taxes	(2,912,531)	-
Total operating expenses	554,641,511	523,196,253
OPERATING INCOME (LOSS)	60,026,130	92,643,088
OTHER INCOME (EXPENSE)	24,280,007	(5,921,972)
INCOME BEFORE INTEREST CHARGES	84,306,137	86,721,116
INTEREST CHARGES:		
Amortization of debt expense	4,204,163	4,143,079
Interest expense	77,046,683	78,681,556
Total interest charges	81,250,846	82,824,635
NET INCOME	3,055,291	3,896,481
RETAINED EARNINGS—Beginning of year	14,238,732	10,342,251
RETAINED EARNINGS—End of year	$ 17,294,023	$ 14,238,732

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
OPERATING ACTIVITIES:		
Net income	$ 3,055,291	$ 3,896,481
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	88,825,066	54,190,596
Amortization of debt expense	4,204,163	4,143,079
Loss (gain) on marketable securities	(16,672,791)	13,147,621
Changes in assets and liabilities:		
Accounts receivable	(10,207,793)	(23,544,559)
Fuel in storage	(27,877,672)	342,925
Materials and supplies	(296,420)	(2,189,366)
Property taxes applicable to future years	(87,500)	(150,000)
Emissions allowances	6,674	57,497
Income tax receivable	2,382,211	65,545
Prepaid expenses and other	(641,810)	(123,945)
Other regulatory assets	9,392,126	(1,146,702)
Other noncurrent assets	1,042,342	(1,244,103)
Accounts payable	(5,360,967)	10,589,698
Accrued taxes	(198,718)	(148,768)
Accrued interest and other	6,869,743	(5,021,649)
Decommissioning, demolition and other	11,899,339	3,076,062
Other liabilities	(3,242,134)	(10,203,483)
Other regulatory liabilities	15,662,796	43,646,969
Net cash provided by operating activities	78,753,946	89,383,898
INVESTING ACTIVITIES:		
Electric plant additions	(12,474,714)	(8,439,941)
Proceeds from sale of long-term investments	55,360,283	71,570,881
Purchases of long-term investments	(98,155,238)	(111,716,117)
Net cash (used in) provided by investing activities	(55,269,669)	(48,585,177)
FINANCING ACTIVITIES:		
Debt issuance and maintenance costs	(3,849,380)	(529,670)
Repayment of Senior 2006 Notes	(22,029,278)	(20,798,412)
Repayment of Senior 2007 Notes	(15,648,462)	(14,759,418)
Repayment of Senior 2008 Notes	(16,992,682)	(15,926,263)
Reissuance 2009A Bonds	25,000,000	-
Redemption of 2009E Bonds	(100,000,000)	-
Issuance of 2019A Bonds	100,000,000	-
Proceeds from line of credit	10,000,000	-
Payments on line of credit	(15,000,000)	-
Principal payments under capital leases	(246,860)	(239,492)
Net cash (used in) provided by financing activities	(38,766,662)	(52,253,255)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(15,282,385)	(11,454,534)
CASH AND CASH EQUIVALENTS—Beginning of year	47,523,556	58,978,090
CASH AND CASH EQUIVALENTS—End of year	$ 32,241,171	$ 47,523,556
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 75,703,531	$ 81,777,903
Income taxes (received) paid—net	$ (4,690,064)	$ (74,784)
Non-cash electric plant additions included in accounts payable at December 31	$ 58,516	$ 892,150

See notes to consolidated financial statements.

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements—The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 24% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2021.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2019, for one year. OVEC anticipates that this agreement will continue until 2022. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA. In 2014, to promote reduced costs, the Companies reduced their billings under the ICPA to effectively forego recovery of the equity return through the ICPA billings. However, in 2018, the Companies discontinued this practice and are once again recovering the equity return through the ICPA billings.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidated balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2019 and 2018, were as follows:

	2019	2018
Regulatory assets:		
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	$ 5,201,536	$ 4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	8,721,689
Total	37,371,844	46,763,970
Total regulatory assets	$ 37,371,844	$ 46,763,970
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 6,182,811	$ 6,024,309
Deferred credit—advance collection of interest	1,494,593	1,633,482
Total	7,677,404	7,657,791
Noncurrent regulatory liabilities:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	2,818,822
Total	189,539,856	138,049,308
Total regulatory liabilities	$ 197,217,260	$ 145,707,099

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and accrued decommissioning and demolition costs to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2019, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2020. Other regulatory liabilities consist primarily of postretirement benefit costs and decommissioning and demolition costs that have been billed to customers in excess of cumulative expense recognition, income taxes refundable to customers that will be credited to bills over a long-term basis, and advanced billings collected from the Sponsoring Companies for debt service.

The regulatory liability for postretirement benefits recorded at December 31, 2019 and 2018, represents amounts collected in historical billings in excess of the accounting principles generally accepted in the United States of America (GAAP) net periodic benefit costs, including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental unfunded plan obligations recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs. Related regulatory liabilities are being credited to customer bills on a long-term basis.

In January 2017, the Companies started advance billing the Sponsoring Companies for debt service as allowed under the ICPA. As of December 31, 2019 and 2018, $90 million and $60 million, respectively, had been advance billed to the Sponsoring Companies. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories, as well as emission allowances, for use in the generation of electricity for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with the provisions of the accounting guidance for Investments—Debt and Equity Securities. Debt and equity securities reflected in long-term investments are carried at fair value with the unrealized gain or loss, reported in Other Income (Expense). The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2019 and 2018 on securities still held at the balance sheet date were $16,445,716 and ($12,968,851), respectively.

Fair Value Measurements of Assets and Liabilities—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 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are being amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidated balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs, including the impacts of the coal combustion residuals rule.

Balance—January 1, 2018	$ 57,170,620
Accretion	3,076,062
Liabilities settled	-
Revisions to cash flows	-
Balance—December 31, 2018	60,246,682
Accretion	3,275,262
Liabilities settled	(34,906)
Revisions to cash flows	-
Balance—December 31, 2019	$ 63,487,038

During 2017, the Companies completed an updated study to estimate the asset retirement costs described above. The revised estimated costs are recorded in the accompanying balance sheets. Adjustments resulting from the revised estimated costs are included as revisions to cash flows in the above table. The increase in the asset retirement obligation is primarily the result of proposed regulations related to the disposal of coal combustion residuals, as further discussed in Note 9.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

Use of Estimates—The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition—In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The Companies implemented the guidance on a modified retrospective basis on January 1, 2018. Revenue for the reporting periods beginning after December 31, 2017, are recorded and disclosed in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The Companies did not make any adjustments to the January 1, 2018, opening balances as a result of adoption, and the implementation had no impact on the Companies' consolidated financial statements.

Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers and the Companies recognize revenue upon billing the customer.

The Companies have three contracts with customers resulting in three types of revenue. These three contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
2) Sales of Electric Energy to Sponsoring Companies
3) Sales of Electric Energy to Pennsylvania, Jersey, Maryland Power Pool (PJM)

The performance obligations and recognition of revenue are similar and both individually and, in the aggregate, were not materially impacted by the implementation of Topic 606. The Companies have no contract assets or liabilities as of December 31, 2019. The following table provides information about the Companies' receivables and unbilled revenue from contracts with customers:

	Accounts Receivable	**Unbilled**
Beginning balance as of January 1, 2018	$ 40,737,337	$ 5,454,632
Ending balance as of December 31, 2018	64,278,896	5,098,515
Increase/(decrease)	$ 23,544,559	$ (356,117)
Beginning balance as of January 1, 2019	$ 64,278,896	$ 5,098,515
Ending balance as of December 31, 2019	$ 74,486,689	$ 5,611,960
Increase/(decrease)	$ 10,207,793	$ 513,445

Recently Issued Accounting Standards—In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost and will also require entities to record allowances for available-for-sale debt securities rather than reduce the carrying amount. The Companies plan to adopt the standard for the fiscal year ended December 31, 2020. The Companies are in the process of evaluating the impact of adoption, if any, of this ASU on the Companies' consolidated financial statements.

See adoption of ASC 842, *Leases*, in Note 11.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 17, 2020, which is the date the consolidated financial statements were issued.

Subsequent to December 31, 2019, the World Health Organization declared the ongoing expansion of an existing outbreak of the SARS-CoV-2 virus, named the coronavirus 2019 ("COVID-19"), a pandemic. As a result of the evolving situation and increasing number of cases, many countries have taken various steps in an attempt to curtail or slow COVID-19's spread, including limiting or ceasing international and domestic travel, slowing or ceasing production activity, and lockdowns or shelter-in-place orders. The Companies are currently unable to predict the duration or extent of any business disruption, changes in law and/or regulation, and uncertainty regarding government and regulatory policy that may occur as a result of these events. COVID-19 has also caused significant volatility and declines in value to most financial markets, which will have a near-term impact on the value of the Companies' long-term investments and investments related to benefit obligations. As there are no comparable recent events which may provide guidance as to the effect of the spread of COVID-19, the Companies are unable to estimate the impact that COVID-19 will have on its financial results at this time.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2019 and 2018 included the sale of all generated power to them, the purchase of Arranged Power from them, and other utility systems in order to meet the DOE's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies; and Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2019 and 2018, balances due from the Sponsoring Companies are as follows:

	2019	**2018**
Accounts receivable	$ 66,926,922	$ 57,442,759

During 2019 and 2018, American Electric Power accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2019. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2019	**2018**
General services	$ 4,830,104	$ 4,917,608
Specific projects	119,157	472,862
Total	$ 4,949,261	$ 5,390,470

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2020 through 2022. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2020 coal requirements under contract. These contracts are based on rates in effect at the time of contract execution. Our total obligations under these agreements as of December 31, 2019, are included in the table below:

2020	$ 213,126,750
2021	$ 135,876,000
2022	$ 50,340,000

4. ELECTRIC PLANT

Electric plant at December 31, 2019 and 2018, consists of the following:

	2019	**2018**
Steam production plant	$2,698,568,508	$2,690,743,500
Transmission plant	81,986,558	81,578,790
General plant	12,909,163	12,917,451
Intangible	26,564	26,564
	2,793,490,793	2,785,266,305
Less accumulated depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	$1,242,919,563	$1,296,155,522

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC had a $200 million revolving credit facility set to expire in November 2019, which was replaced on April 25, 2019, by a new revolving credit facility of $185 million with an expiration date of April 25, 2022. At December 31, 2019 and 2018, OVEC had borrowed $80 million and $85 million, respectively, under lines of credit. Interest expense related to lines of credit borrowings was $3,757,148 in 2019 and $3,448,137 in 2018. During 2019 and 2018, OVEC incurred annual commitment fees of $268,285 and $318,885, respectively, based on the borrowing limits of the lines of credit.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2019 and 2018:

	Interest Rate Type	Interest Rate	2019	2018
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 168,569,904	$ 189,381,919
2006B due June 15, 2040	Fixed	6.40	54,142,874	55,360,136
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	74,610,818	84,386,325
2007A-B due February 15, 2026	Fixed	5.90	18,790,003	21,251,868
2007A-C due February 15, 2026	Fixed	5.90	18,939,620	21,421,088
2007B-A due June 15, 2040	Fixed	6.50	27,012,831	27,630,240
2007B-B due June 15, 2040	Fixed	6.50	6,802,916	6,958,404
2007B-C due June 15, 2040	Fixed	6.50	6,857,084	7,013,810
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	23,292,665	26,342,332
2008B due February 15, 2026	Fixed	6.71	47,301,931	53,467,070
2008C due February 15, 2026	Fixed	6.71	49,367,759	55,446,166
2008D due June 15, 2040	Fixed	6.91	39,387,935	40,230,351
2008E due June 15, 2040	Fixed	6.91	40,072,323	40,929,376
Series 2009 Bonds:				
2009A due February 15, 2026	Fixed	2.88	25,000,000	-
2009B due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009C due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009D due February 1, 2026	Floating	1.46	25,000,000	25,000,000
2009E due October 1, 2019	Fixed	5.63	-	100,000,000
Series 2010 Bonds:				
2010A due February 1, 2040	Floating	6.23	50,000,000	50,000,000
2010B due February 1, 2040	Floating	3.31	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due June 1, 2032	Fixed	5.00	76,800,000	76,800,000
2012A due June 1, 2039	Fixed	5.00	123,200,000	123,200,000
2012B due June 1, 2040	Floating	6.23	50,000,000	50,000,000
2012C due June 1, 2040	Floating	6.23	50,000,000	50,000,000
Series 2017 Notes:				
2017A due August 4, 2022	Floating	6.23	100,000,000	100,000,000
Series 2019 Bonds:				
2019A due September 1, 2029	Fixed	3.25	100,000,000	-
Total debt			1,275,148,663	1,304,819,085
Total premiums and discounts (net)			(437,865)	(460,465)
Less unamortized debt expense			(13,754,586)	(14,618,729)
Total debt net of premiums, discounts, and unamortized debt expense			1,260,956,212	1,289,739,891

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

In 2009, the Ohio Air Quality Development Authority (the "OAQDA") issued the variable-rate, non-amortizing, tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) in four series (Series 2009A, Series 2009B, Series 2009C and Series 2009D) of $25 million each (the "Series 2009A Bonds," the "Series 2009B Bonds," the "Series 2009C Bonds" and the "Series 2009D Bonds") and $100 million fixed-rate non-amortizing tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2009E Bonds"), the proceeds of which were used to finance a portion of OVEC's costs of acquiring, constructing and installing certain solid waste disposal facilities comprising "air quality facilities," as defined in Chapter 3706, Ohio Revised Code, as amended, for Units 1-5 of the Kyger Creek Plant. OVEC is obligated to make payments under loan agreements between OVEC and OAQDA equal to the principal and interest payments due on such bonds, among other payments.

The Series 2009B and Series 2009C Bonds were remarketed in August 2016, for a five-year interest period that extends to August 25, 2021. The Series 2009A Bonds were secured by an irrevocable transferable direct-pay letter of credit at December 31, 2016, but were repurchased by OVEC on February 6, 2017. Further, the Series 2009D Bonds were secured by an irrevocable transferable direct-pay letter of credit that expired on November 14, 2019. On August 14, 2019, the Series 2009A Bonds and Series 2009D Bonds were each reoffered with a fixed interest rate of 2.875% per annum for the period beginning on August 28, 2019 and ending on February 1, 2026. In addition, the Series 2009E Bonds, which were scheduled to mature on October 1, 2019, were refunded with the proceeds of the Series 2019A Bonds (as defined below).

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million variable-rate bonds due on February 1, 2040. In June 2011, the $100 million variable-rate bonds were reissued by the Indiana Finance Authority (the "IFA") as two series of $50 million variable-rate, non-amortizing, tax-exempt bonds: the Series 2010A Bonds, with an interest period of three years and the Series 2010B Bonds, with an interest period of five years. The Series 2010B Bonds were remarketed in August 2016 for another five-year interest period ending on August 25, 2021. The Series 2010A Bonds were remarketed in June 2014 for a three-year period and in September 2017 for another three-year period that extends to August 4, 2020. The Series 2010A Bonds are to be refinanced in 2020. The Series 2010B Bonds are not being reoffered at this time.

During 2012, the IFA issued $200 million fixed-rate, tax-exempt Midwestern Disaster Relief Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2012A Bonds") and two series of $50 million each, variable-rate, tax-exempt bonds: the Series 2012B Bonds and the Series 2012C Bonds. The Series 2012A Bonds will begin amortizing on June 1, 2027, up to its maturity date. OVEC is obligated to make payments under loan agreements between OVEC and the IFA equal to the principal and interest payments due on such bonds, among other payments.

In 2017, the Series 2012B Bonds and the Series 2012C Bonds, which had been secured by irrevocable transferable direct-pay letters of credit, were remarketed with four-year and five-year interest periods expiring August 4, 2021 and August 4, 2022, respectively.

During 2017, OVEC issued $100 million 2017A variable-rate non-amortizing unsecured senior notes ("2017A Notes") to refinance and retire a 2013 series of notes ("2013A Notes"). The 2013A Notes had an original maturity date of February 15, 2018. The 2017A Notes have an annual repayment of $33,333,333 on August 4, 2020, August 4, 2021, and at the maturity date of August 4, 2022.

In August 2019, OVEC refinanced or refunded $150 million in tax-exempt bonds as follows: (i) the OAQDA issued the State of Ohio Air Quality Revenue Refunding Bonds (Ohio Valley Electric Corporation Project), Series 2019A in an aggregate principal amount of $100 million (the "Series 2019A Bonds"), with a fixed interest rate of 3.25% per annum for the period beginning August 28, 2019 to September 1, 2029, the proceeds of which were used to refund the Series 2009E Bonds, (ii) the Series 2009A Bonds were reoffered in an aggregate principal amount of $25 million and (iii) the Series 2009D Bonds were reoffered in an aggregate principal amount of $25 million.

The annual maturities of long-term debt as of December 31, 2019, are as follows:

2020	$ 141,387,803
2021	244,982,570
2022	148,800,891
2023	69,523,395
2024	73,831,592
2025–2040	596,622,412
Total	$1,275,148,663

Note that the 2020 maturities of long-term debt include $50 million variable-rate bonds with agreements expiring in August 2020.

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2019	2018
Income tax expense at statutory rate (21% 2019, 21% 2018)	$ 29,980	$ 818,261
Temporary differences flowed through to customer bills	(2,948,492)	(823,343)
Permanent differences and other	5,981	5,082
Income tax provision	$ (2,912,531)	$ -

Components of the income tax provision were as follows:

	2019	2018
Current income tax expense—federal	$ (2,912,531)	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	-	-
Total income tax provision	$ (2,912,531)	$ -

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. These temporary differences will be credited to the Sponsoring Companies through future power billings. The regulatory liability was $8,658,898 and $11,571,429 at December 31, 2019 and 2018, respectively.

Deferred income tax assets (liabilities) at December 31, 2019 and 2018, consisted of the following:

	2019	2018
Deferred tax assets:		
Deferred revenue—advances for construction	$ 1,299,537	$ 1,265,885
Federal net operating loss carryforwards	39,691,784	49,663,022
Postretirement benefit obligation	891,785	2,140,505
Pension liability	7,034,974	6,447,661
Postemployment benefit obligation	1,093,288	871,608
Asset retirement obligations	13,344,057	12,659,609
Advanced collection of interest and debt service	19,230,828	12,951,016
Miscellaneous accruals	1,154,630	1,183,464
Regulatory liability—postretirement benefits	16,008,318	13,376,650
Regulatory liability—asset retirement costs	3,093,544	-
Regulatory liability—income taxes refundable to customers	4,549,301	5,484,284
Total deferred tax assets	107,392,046	106,043,704
Deferred tax liabilities:		
Prepaid expenses	(384,597)	(352,638)
Electric plant	(81,887,070)	(81,674,810)
Unrealized gain/loss on marketable securities	(4,348,230)	(855,225)
Regulatory asset—pension benefits	(6,719,696)	(7,122,200)
Regulatory asset—asset retirement costs	-	(1,240,367)
Regulatory asset—unrecognized postemployment benefits	(1,093,288)	(871,608)
Total deferred tax liabilities	(94,432,881)	(92,116,848)
Valuation allowance	(12,959,165)	(13,926,856)
Deferred income tax assets	$ -	$ -

Because future taxable income may prove to be insufficient to recover the Companies' deferred tax assets, the Companies have recorded a valuation allowance for their deferred tax assets as of December 31, 2019 and 2018. During 2016, due to a change in federal tax law, the Companies recorded as receivables certain AMT credit carryforwards that the Companies expect to claim as refundable credits in their 2018–2022 federal income tax returns. The amount of the refundable AMT credit is reflected as a current receivable of

$2,307,341 and a non-current receivable of $2,307,341 for a total receivable of $4,614,682.

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2019 and 2018, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2015 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2015 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2014 and earlier. The Companies have $189,008,494 of Federal Net Operating Loss carryovers that begin to expire in 2032.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees hired prior to January 1, 2015. The benefits are based on years of service and each employee's highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially, all of the Companies' employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2018.

The Pension Plan's assets as of December 31, 2019, consist of investments in equity and debt securities. All of the trust funds' investments for the pension and postemployment benefit plans are diversified and managed in compliance with all laws and regulations.

Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	15 %
International and global equity	15
Fixed income	68
Cash	2

VEBA Plan Assets	**Target**
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Equity investment limitations:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

Fixed-Income Limitations—As of December 31, 2019, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2019 and 2018, are as follows:

	Pension Plan		**Other Postretirement Benefits**	
	2019	**2018**	**2019**	**2018**
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 234,099,137	$ 256,019,423	$ 151,305,246	$ 168,487,209
Service cost	6,078,450	7,108,309	3,428,368	4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Net actuarial loss (gain)	30,255,836	(28,186,233)	21,462	(17,121,066)
Plan amendments [(1)] [(2)]		-	3,989,560	(6,648,237)
Settlement [(3)]	(27,857,703)	-	-	-
Expenses paid from assets	(36,469)	(46,647)	-	-
Projected benefit obligation—end of year	244,541,899	234,099,137	159,833,696	151,305,246
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	200,204,812	218,769,576	141,118,649	151,290,524
Actual return on plan assets	42,540,447	(14,277,140)	19,940,452	(6,304,997)
Expenses paid from assets	(36,469)	(46,647)	-	-
Employer contributions	5,600,000	6,000,000	13,853	40,099
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Settlement	(27,857,703)	-	-	-
Fair value of plan assets—end of year	212,371,591	200,204,812	155,590,848	141,118,649
Underfunded status—end of year	$ (32,170,308)	$ (33,894,325)	$ (4,242,848)	$ (10,186,597)

(1) The $3.9M plan amendment is the result of the change of the long-term retiree cost sharing through retiree contributions for pre-65 retirees from 20% to 12%.

[(2)] The $6.6M plan amendment is the result of the termination of the active/pre-65 retiree PPO and indemnity plans. All participants in those plans were moved to the CDHP.

[(3)] The $27.9M settlement is the result of an annuity purchase of about $22.7M for 162 retirees and beneficiaries which was paid on November 25, 2019 and the lump sums payments totaling about $5.2M during 2019.

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

The accumulated benefit obligation for the Pension Plan was $218,590,886 and $212,367,000 at December 31, 2019 and 2018, respectively.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under generally accepted accounting principles, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2019	2018	2019	2018
Service cost	$ 6,078,450	$ 7,108,309	$ 3,428,368	$ 4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Expected return on plan assets	(11,867,776)	(13,034,239)	(7,515,431)	(8,062,728)
Amortization of prior service cost	(416,565)	(416,565)	(3,145,420)	(2,536,062)
Recognized actuarial loss (gain)	1,234,195	1,049,337	-	-
Cost of Settlements	3,570,924	-	-	-
Total benefit cost	$ 8,681,372	$ 4,152,104	$ (661,317)	$ (104,473)
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,600,000	$ 6,000,000	$ -	$ -

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 8,792,346	$ -	$ -	$ 8,792,346
Equity mutual funds	42,776,633	-	-	42,776,633
Index futures	-	230	-	230
Fixed-income securities	-	140,413,999	-	140,413,999
Commodities	-	43	-	43
Cash equivalents	7,154,484	-	-	7,154,484
Subtotal benefit plan assets	$ 58,723,463	$ 140,414,272	$ -	199,137,735
Investments measured at net asset value (NAV)				13,233,857
Total benefit plan assets				$ 212,371,592
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 7,138,880	$ -	$ -	$ 7,138,880
Equity mutual funds	35,494,238	-	-	35,494,238
Index futures	-	81	-	81
Fixed-income securities	-	142,452,199	-	142,452,199
Commodities	-	47	-	47
Cash equivalents	3,719,257	-	-	3,719,257
Subtotal benefit plan assets	$ 46,352,375	$ 142,452,327	$ -	188,804,702
Investments measured at net asset value (NAV)				11,400,110
Total benefit plan assets				$ 200,204,812

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**2019 Total**
Equity mutual funds	$ 54,952,087	$ -	$ -	$ 54,952,087
Fixed-income mutual funds	75,428,176	-	-	75,428,176
Fixed-income securities	-	21,122,393	-	21,122,393
Cash equivalents	1,175,475	-	-	1,175,475
Benefit plan assets	$ 131,555,738	$ 21,122,393	$	152,678,131
Uncleared cash disbursements from benefits paid				(5,468,253)
Investments measured at net asset value (NAV)				8,380,969
Total benefit plan assets				$ 155,590,847
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	$ 46,690,283	$ -	$ -	$ 46,690,283
Fixed-income mutual funds	69,726,689	-	-	69,726,689
Fixed-income securities	-	19,673,412	-	19,673,412
Cash equivalents	1,866,335	-	-	1,866,335
Benefit plan assets	$ 118,283,307	$ 19,673,412	$ -	137,956,719
Uncleared cash disbursements from benefits paid				(3,866,878)
Investments measured at net asset value (NAV)				7,028,808
Total benefit plan assets				$ 141,118,649

Investments that were measured at net asset value (NAV) per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2019 and 2018, were as follows:

	Pension Plan		**Other Postretirement Benefits**			
	2019	**2018**	**2019**		**2018**	
			Medical	**Life**	**Medical**	**Life**
Discount rate	3.58 %	4.40 %	3.55 %	3.55 %	4.40 %	4.40 %
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018, were as follows:

	2019	2018	2019		2018	
			Medical	Life	Medical	Life
Discount rate	4.40 %	3.75 %	4.40 %	4.40 %	3.76 %	3.76 %
Expected long-term return on plan assets	6.00	6.00	5.33	6.00	5.33	6.00
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2019 and 2018, were as follows:

	2019	2018
Health care trend rate assumed for next year—participants under 65	7.00 %	7.00 %
Health care trend rate assumed for next year—participants over 65	7.30	19.40
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service and interest cost	$ 1,274,727	$ (1,043,944)
Effect on postretirement benefit obligation	19,856,817	(16,262,286)

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2019 and 2018, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2019	2018	2019	2018
Asset category:				
Equity securities	31 %	27 %	39 %	37 %
Debt securities	69	73	61	63

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,800,000 to their Pension Plan and $21,500 to their Other Postretirement Benefits plan in 2020.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2020	$ 9,176,543	$ 6,640,020
2021	9,826,112	7,064,850
2022	10,603,824	7,596,021
2023	11,268,181	8,175,889
2024	12,239,883	8,788,750
Five years thereafter	66,774,987	49,888,077

Postemployment Benefits—The Companies follow the accounting guidance in FASB ASC 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 42% and 58% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 59% and 41% split between OVEC and IKEC, respectively, as of December 31, 2018. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $5,201,536 and $4,147,956 at December 31, 2019 and 2018, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees, hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2019 and 2018 were $1,966,847 and $2,014,215, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required significant reductions of SO_2 and NO_x emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO_x, 2010 and 2015 for SO_2, and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these rules. Following completion of the necessary engineering and permitting, construction was started on the FGD systems, and the two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

After the promulgation of CAIR and CAMR, a series of legal challenges to those rules resulted in their replacement with additional rules. CAMR was replaced with a rule referred to as the Mercury and Air Toxics Standards (MATS) rule. The rule became final on April 16, 2012, and the Companies had to demonstrate compliance with MATS emission limits on April 16, 2015. The MATS rule has also undergone legal challenges since it went into effect, and there are a few remaining legal issues pending. The controls the Companies have installed have proven to be adequate to meet the stringent emissions requirements outlined in the MATS rule.

After CAIR was promulgated, legal challenges resulted in that rule being remanded back to the U.S. EPA. The U.S. EPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule (CSAPR). CSAPR was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, a legal challenge of that rule resulted in a stay. The stay was lifted by the D.C. Circuit Court in 2014 and CSAPR, which requires significant NO_x and SO_2 emissions reductions, became effective on January 1, 2015. Further legal challenges of CSAPR resulted in the U.S. Supreme Court remanding portions of the CSAPR rule back to the D.C. Circuit Court for additional review and subsequent action by the U.S. EPA. This resulted in U.S. EPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update did not replace CSAPR, it only required additional reductions in NO_x emissions from utilities in twenty-two states (including Ohio and Indiana) during the ozone season. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update rule requirements in the 2017 ozone season. That strategy was standardized to meet future ozone season compliance obligations, and its execution provided for another successful ozone season in 2019. The CSAPR Update Rule has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, on one of those legal challenges that remanded portions of this rule back to U.S. EPA to address. The EPA has not yet acted on the remand; however, the Companies are not currently anticipating any potential changes in the rule to address the D.C. Circuit Court remand that would materially impact our current compliance strategy or change future operations.

As a result of the installation and effective operation of the FGD systems and the SCR systems at each plant, management did not need to purchase additional annual SO_2 allowances, annual NO_x allowances or ozone season NO_x allowances in 2019 to cover actual emissions. The Companies also maintain a bank of allowances for all three programs as a hedge to cover future emissions in the event of any short-term operating events or other external factors. Depending on a variety of operational and economic factors, management may elect to consume a portion of these banked allowances and/or strategically purchase additional CSAPR annual and ozone season allowances in 2020 and beyond for compliance with the CSAPR and CSAPR Update rules.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available every year without having to rely on market purchases to comply with the CSAPR rules in their current form. Given the success of the Companies' NO_x ozone season compliance strategy, the purchase of additional NO_x allowances is less likely in the short term as well; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons and are continuing to evaluate the need for additional NO_x controls for this unit to provide additional flexibility in operating this unit in the event future NO_x regulations place additional emission constraints on the utility industry.

CCR Rule

In 2010, the U.S. EPA published a proposed rule to regulate the disposal and beneficial reuse of coal combustion residuals (CCRs), including fly ash and boiler slag generated at coal-fired electric generating units as well as FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial reuse and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the U.S. EPA issued a prepublication copy of its final rule in December 2014. The rule was published in the Federal Register in April 2015 and became effective in October 2015.

In the final rule, the U.S. EPA elected to regulate CCR as a nonhazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action. As a result of this self-implementing feature, the rule contains extensive recordkeeping, notice, and Internet posting requirements.

The Companies have been systematically implementing the applicable provisions of the CCR rule. The Companies have completed all compliance obligations associated with the rule to date and are continuing to evaluate what, if any, impacts groundwater quality will have on the South Fly Ash Pond and landfill at Kyger Creek and the West Boiler Slag Pond and landfill at Clifty Creek. To date, these four CCR units continue to meet the groundwater monitoring standards of the CCR Rule. The Companies have been evaluating potential impacts to groundwater quality near the boiler slag pond at Kyger Creek and the landfill runoff collection pond at Clifty Creek as required by the CCR Rule. The Companies have determined that statistically significant increases (SSIs) in certain groundwater parameters are present at the two identified locations, and additional steps as defined by the CCR rule were taken. The evaluation of whether an SSI exists is a required component of the groundwater monitoring conditions of the CCR rule. A determination that an SSI appears to be present requires additional evaluation to be undertaken by the facility to determine if there are alternative sources that are influencing groundwater quality and to evaluate the extent of the groundwater quality impact. Concurrently, a facility must continue to evaluate groundwater quality as required by the CCR rule, and determine what potential corrective actions are feasible to address the SSIs. The Companies conducted Alternative Source Demonstrations (ASD) to determine if groundwater was being influenced from sources other than the CCR unit. The ASDs were unable to definitively prove that alternative sources were directly influencing groundwater quality. As a result, the Companies worked with their Qualified Professional Engineer (QPE) to determine what corrective actions were feasible for each CCR unit, and then held a public meeting to discuss these options with the public prior to selecting a remedy. The Companies continue to work through the compliance requirements of the CCR Rule and remain in compliance.

Since the initial rollout of the CCR rules in 2015, several legal, legislative and regulatory events impacting the scope, applicability and future CCR compliance obligations and timelines have also taken place. Final actions include federal legislation (i.e., the WIIN Act) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program, U.S. EPA's issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018, and the D.C. Circuit Court's August 21, 2018, ruling vacating and remanding portions of the CCR rule. In addition, the U.S. EPA announced plans to issue additional revisions to the CCR rule, some of which would also directly address the D.C. Circuit Court's issues raised in its August 21, 2018, decision. Other proposed revisions to the 2015 CCR rules that the U.S. EPA is currently undertaking will address outstanding issues previously identified by the agency and the Court. Two draft CCR rules entitled Part A and Part B, are in the public notice phase and are expected to be issued in final form later in 2020. Part A proposes a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the 2015 CCR rule to cease receiving CCR material and initiate closure by August 31, 2020, regardless of their overall compliance status. If that date is not technically feasible, an alternate date to cease receiving CCR material and initiate closure can be secured from U.S. EPA through a proposed extension request process. The surface impoundments at Kyger Creek and Clifty Creek do not meet the liner design requirements required under the 2015 CCR rule. As a result, the Companies have begun an engineering evaluation to determine a technically feasible timeline for discontinuing placement of CCR materials in these impoundments and the initiation of closure consistent with the draft rule. Subsequently, the Companies intend to submit a technical justification document to U.S. EPA that demonstrates why additional time is needed to cease placement of CCR in the surface impoundments and initiate closure. The Companies anticipate U.S. EPA will approve the alternative schedule at this time. Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with U.S. EPA or any state regulatory that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly. Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations.

In February 2014, the U.S. EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the U.S. EPA supports these beneficial uses. Currently, approximately 60 percent of the coal ash and other residual products from our generating facilities are reused in the production of cement and wallboard, as soil amendments, as abrasives or road treatment materials, and for other beneficial uses.

NAAQS Compliance for SO_2

On June 22, 2010, the U.S. EPA revised the Clean Air Act by developing and publishing a new one-hour SO_2 NAAQS of 75 parts per billion, which replaced the previously existing 24-hour and annual standards, and became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the U.S. EPA published its initial non-attainment area designations for the new one-hour SO_2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons SO_2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, U.S. EPA entered into a settle agreement with Sierra Club/NRDC in the U.S. District Court for the Northern District of California requiring U.S. EPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO_2 or more than 2,600 tons with a 0.45 SO_2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO_2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by U.S. EPA as inconclusive in 2016. As a result, U.S. EPA required Kyger Creek install an SO_2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, Ohio EPA will be preparing an updated petition to U.S. EPA requesting that the area in the county surrounding the plant be designated in attainment of the one-hour standard. Finally, on February 26, 2019, the U.S. EPA issued a final decision that it is retaining the existing primary SO_2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO_2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

Steam Electric ELGs

On September 30, 2015, the U.S. EPA signed a new final rule governing Effluent Limitations Guidelines (ELGs) for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the Federal Register on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek Stations.

The rule was intended to require the Companies to modify the way they handle a number of wastewater processes at both power plants. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the U.S. EPA issued an administrative stay on the ELG rule; and then in June 2017, the U.S. EPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The U.S. EPA has been working to revise the rule to evaluate what constitutes "best available technology" for these two wastewater discharges and issue an updated rule by no later than the fall of 2020. While the revised rule is not yet final, the Companies' understanding of what the original impacts and updated impacts to each wastewater discharge are highlighted below:

1. Kyger Creek will need to convert to dry fly ash handling by no later than December 31, 2023. The U.S. EPA stay on portions of the ELG rule does not impact the need to convert Kyger Creek Station to dry fly ash handling or the associated timeline. The Clifty Creek Station already has a dry fly ash handling system in place, so this provision of the rule will not impact Clifty Creek's operations.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. For Clifty Creek and Kyger Creek, this will likely result in the conversion of each plant's boiler slag pond to a closed-loop sluicing system for boiler slag. The Companies conducted a Phase I engineering study in 2016 to determine options and costs associated with retrofitting the plants' boiler slag treatment systems but postponed the study until more information was available from U.S. EPA on the technologies being considered in the revised rule. After reviewing the new draft rule, the Companies resumed the engineering study needed to formulate an overall compliance strategy based on this updated information. This study includes a further evaluation of technologies or retrofits capable of complying with the requirements of the revised rule, which include preliminary engineering, design, and schedule development that were initiated late in 2019. The results of that evaluation are expected to be available in the second quarter of 2020.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there were to be new internal limits for arsenic, mercury, selenium, and nitrate/nitrite nitrogen from the FGD chlorides purge stream wastewater treatment plant at each plant. For both Clifty Creek and Kyger Creek Stations, the Companies were expecting to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies were expecting to add some form of biological (or equivalent nonbiological) treatment system on the back end of each Station's existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule are currently on hold while the Companies await further regulatory action from the U.S. EPA that will determine what the new limits for each of these constituents will be in the final ELG rule, which is expected late fall 2020. Once those final effluent limits are established, the Companies will resume evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements. Based on the Companies' review of the draft revised ELG rule, the compliance deadline for FGD wastewater has been moved to compliance with the updated requirements no later than December 31, 2025.

Any new ELG limits will be implemented through each Station's wastewater discharge permit, which is typically renewed on a five-year basis. The final compliance dates are expected to be facility-specific and negotiated with the Companies' state permit agencies based on the time needed to plan, secure funding, design, procure, and install necessary control technologies once the new rulemaking has been completed. The Companies will continue to monitor EPA regulatory actions on this rule and will respond as necessary.

316(b) Compliance

The 316(b) rule was published as a final rule in the Federal Register on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

The timeline for determining if retrofits may be required to the cooling water systems at either Clifty Creek or Kyger Creek, as well as the type of retrofit required, will be negotiated with each state regulatory agency during future NPDES Permit renewals consistent with state regulatory obligations under 40 CFR Section 125.98(f).

The environmental rules and regulations discussed throughout the Environmental Matters footnote could require additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings because they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. 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.

As of December 31, 2019 and 2018, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments. The investments consist of money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2019 and 2018, were as follows:

	Fair Value Measurements at Reporting Date Using		
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ 99,982,734	$ -	$ -
Fixed-income mutual funds	37,002,850	-	-
Fixed-income municipal securities		101,374,099	-
Cash equivalents	2,379,596	-	-
Total fair value	$139,365,180	$101,374,099	$ -
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 64,095,224	$ -	$ -
Fixed-income mutual funds	22,186,437	-	-
Fixed-income municipal securities	-	93,085,183	-
Cash equivalents	1,904,689	-	-
Total fair value	$ 88,186,350	$ 93,085,183	$ -

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2019 and 2018, are as follows:

	2019		**2018**	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	1,390,779,759	1,275,148,664	1,398,244,690	1,329,819,085

11. LEASES

OVEC has various operating leases for the use of other property and equipment.

On January 1, 2019, the Companies adopted ASC 842, "Leases" which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet along with a corresponding right-of-use asset. Results for reporting periods beginning January 1, 2019, are presented under Topic 842, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting under Topic 840. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments, and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

Upon adoption of ASC 842, the impact was a $22,000 increase in ROU assets and operating lease obligations. These adjustments are the result of assigning a right-of-use asset and related lease liability to the Companies operating leases. There were no cumulative effect adjustments to opening retained earnings, and adoption of the lease standard had no impact to cash from or used in operating, financing, or investing activities on the cash flow statement.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term.

The leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

The Companies have operating and finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 1 year to 7 years. The components of lease expense were as follows:

Year Ending December 31,	**2019**
Operating lease cost	$ 15,095
Finance lease cost:	
Amortization of leased assets	$ 258,411
Interest on lease liabilities	61,547
Total finance lease cost	$ 319,958

Supplemental cash flow information related to leases was as follows:

Operating cash flows from operating leases	$15,095
Operating cash from finance leases	55,793
Financing cash flows from finance leases	156,130
Weighted average remaining lease term:	
Operating leases	< 1 year
Finance leases	4 years
Weighted average discount rate:	
Operating leases	3.8 %
Finance leases	8.1 %

The amount of operating lease ROU assets and liabilities is $7,431 and $0 as of December 31, 2019 and 2018, respectively.

The amount in property under finance leases is $1,545,051 and $1,156,718 with accumulated depreciation of $669,164 and $464,194 as of December 31, 2019 and 2018, respectively.

Future cash flows of operating leases, and maturities of financing lease liabilities are as follows:

Years Ending December 31	**Operating**	**Finance**
2020	$ 7,512	$291,782
2021	-	221,997
2022	-	151,065
2023	-	89,223
2024	-	55,121
Thereafter	-	105,649
Total future minimum lease payments	$ 7,512	914,837
Less estimated interest element		168,135
Estimated present value of future minimum lease payments		$746,702

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

On March 31, 2018, FirstEnergy Solutions Corp. (FES), one of the Sponsoring Companies under the ICPA, filed for Chapter 11 bankruptcy protection under the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Ohio (the "Bankruptcy Court"). OVEC made a preemptive filing on March 26, 2018, at the Federal Energy Regulatory Commission (FERC) requesting either (i) an order finding that FES's anticipated rejection of the ICPA would constitute a violation of that agreement's terms and would not satisfy the Federal Power Act's "public interest" standard, or, (ii) an order declaring that FERC has exclusive jurisdiction over the proposed rejection of the ICPA (the "FERC Action"). On April 1, 2018, FES filed in the Bankruptcy Court a motion to reject the ICPA and separately obtained an order temporarily enjoining the FERC Action. On May 11, 2018, the Bankruptcy Court granted a preliminary injunction enjoining FERC from reviewing FES's requested rejection of the ICPA under the public interest standard. FERC subsequently filed an appeal of this decision with the United States Court of Appeals for the Sixth Circuit (the "Injunction Appeal"), which OVEC joined as an intervenor. On July 31, 2018, the Bankruptcy Court granted FES's motion to reject the ICPA using the "business judgement" standard used to evaluate contract rejection under the Bankruptcy Code (the "Rejection Order"). Per the ICPA, upon rejection, OVEC made available to all other Sponsoring Companies FES's entitlement to available energy under the ICPA. OVEC appealed the Rejection Order to the Sixth Circuit (the "Rejection Appeal"). The Rejection Appeal was ultimately consolidated with the Injunction Appeal (together as consolidated, the "Sixth Circuit Rejection Appeal"). On December 12, 2019, the U.S. Court of Appeals for Sixth Circuit ruled on the Sixth Circuit Rejection Appeal by (1) affirming the Bankruptcy Court's jurisdiction over the rejection of the ICPA and (2) finding that the Bankruptcy Court should have considered the public interest in the standard for rejection and remanding to the Bankruptcy Court for further consideration under a heightened standard, after giving FERC a reasonable opportunity to weigh in. OVEC filed a petition for rehearing "en banc," and on March 13, 2020, the Sixth Circuit denied the petition.

On July 31, 2019, OVEC and FES entered into a stipulation with respect to OVEC's objection to confirmation of the FES plan of reorganization, stipulating that FES (a) would not seek to dismiss OVEC's Sixth Circuit appeal, or, if applicable, OVEC's appeal of an order with respect to an objection by OVEC to confirmation of the plan arising under section 1129(a)(6) of the Bankruptcy Code or oppose further review by the United States Supreme Court, on the grounds of mootness. OVEC objected to confirmation of the FES plan under section 1129(a)(6) of the Bankruptcy Code, which requires any governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of a debtor to approve any rate change provided for in the plan, or that such rate change is expressly conditioned on such regulatory approval. OVEC's objection was overruled at the confirmation hearing on August 20th and 21st. The FES plan of reorganization was confirmed on October 16, 2019. On October 29, 2019, OVEC moved to certify a direct appeal of the Bankruptcy Court's confirmation order to the Sixth Circuit. On November 27, 2019, the Bankruptcy Court granted OVEC's motion to certify the confirmation order for direct appeal to the Sixth Circuit. On March 24, 2020, the Sixth Circuit granted OVEC's petition for direct appeal of the confirmation order.

On October 14, 2018, OVEC filed with the Bankruptcy Court its rejection damages claim of approximately $540 million against FES. The amount of OVEC's rejection damages claim has not been litigated at this time. Until the outcome of the Sixth Circuit Appeal and, potentially, a subsequent proceeding at FERC, it is undetermined whether FES will ultimately be permitted to reject its interest in the ICPA. FES's share of obligations, in each case under the ICPA, is approximately 5%. However, the Companies currently have access to the credit markets to fund ongoing liquidity needs, and the Sponsoring Companies remain obligated to fund debt service payments when due. The Companies accounts receivables as of December 31, 2019, on the consolidated balance sheets include receivables for FES's share of the Sponsor billings from March 2018 through December 31, 2019, which amounts to $38.5 million at December 31, 2019.

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