Ohio Valley Electric Corporation and Subsidiary Company

Consolidated Financial Statements as of and for the Years Ended December 31, 2018 and 2017, and Independent Auditors' Report

Deloitte & Touche LLP
250 East 5th Street
Suite 1900
Cincinnati, OH 45202-5109
USA

Tel:+1 513 784 7100
Fax:+1 513 784 7204
www.deloitte.com

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, 2018 and 2017, and the related consolidated statements of income and 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 audits 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, 2018 and 2017, 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 11, 2019

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2018 AND 2017

	2018	2017
ASSETS		
ELECTRIC PLANT:		
At original cost	2,785,266,305	2,782,873,612
Less—accumulated provisions for depreciation	1,500,183,895	1,445,352,656
	1,285,082,410	1,337,520,956
Construction in progress	11,073,112	6,493,278
Total electric plant	1,296,155,522	1,344,014,234
CURRENT ASSETS:		
Cash and cash equivalents	47,523,556	58,978,090
Accounts receivable	64,278,896	40,734,337
Fuel in storage	33,474,186	33,817,111
Emission allowances	298,355	355,852
Materials and supplies	40,634,643	38,445,277
Income taxes receivable	4,690,064	0
Property taxes applicable to future years	3,062,500	2,912,500
Prepaid expenses and other	2,175,905	2,051,978
Total current assets	196,138,105	177,295,145
REGULATORY ASSETS:		
Unrecognized postemployment benefits	4,147,956	3,865,985
Unrecognized pension benefits	33,894,325	37,249,847
Decommissioning and demolition	5,902,867	678,154
Total regulatory assets	43,945,148	41,793,986
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	156,683	327,610
Long-term investments	181,271,533	154,273,960
Income taxes receivable	4,614,683	9,294,909
Other	1,245,637	1,534
Total deferred charges and other	187,288,536	163,898,013
TOTAL	1,723,527,311	1,727,001,378

(Continued)

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2018 AND 2017

	2018	2017
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2018 and 2017	$ 10,000,000	$ 10,000,000
Long-term debt	1,110,069,775	1,261,297,697
Line of credit borrowings	-	85,000,000
Retained earnings	14,238,732	10,342,251
Total capitalization	1,134,308,507	1,366,639,948
CURRENT LIABILITIES:		
Current portion of long-term debt	179,670,116	76,483,805
Line of credit borrowings	85,000,000	-
Accounts payable	41,313,387	31,331,422
Accrued other taxes	10,725,765	10,799,150
Regulatory liabilities	7,657,791	1,909,470
Accrued interest and other	20,663,191	25,684,840
Total current liabilities	345,030,250	146,208,687
COMMITMENTS AND CONTINGENCIES (Notes 3, 11, 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	63,659,058	56,495,826
Income taxes refundable to customers	11,571,428	11,571,428
Advance billing of debt reserve	60,000,000	30,000,000
Total regulatory liabilities	135,230,486	98,067,254
OTHER LIABILITIES:		
Pension liability	33,894,325	37,249,847
Asset retirement obligations	60,246,682	57,170,620
Postretirement benefits obligation	10,186,597	17,196,685
Postemployment benefits obligation	4,147,956	3,865,985
Other noncurrent liabilities	482,508	602,352
Total other liabilities	108,958,068	116,085,489
TOTAL	1,723,527,311	1,727,001,378

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, 2018 AND 2017

	2018	2017
REVENUES FROM CONTACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 7,605,922	$ 8,187,803
Sponsoring companies	608,233,419	615,870,005
Total operating revenues	615,839,341	624,057,808
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	277,368,623	288,503,093
Purchased power	6,863,294	6,922,507
Other operation	86,302,869	85,206,695
Maintenance	86,305,942	82,862,095
Depreciation	54,190,596	84,699,703
Taxes—other than income taxes	12,164,929	11,975,463
Total operating expenses	523,196,253	560,169,556
OPERATING INCOME (LOSS)	92,643,088	63,888,252
OTHER INCOME (EXPENSE)	(5,921,972)	12,619,686
INCOME BEFORE INTEREST CHARGES	86,721,116	76,507,938
INTEREST CHARGES:		
Amortization of debt expense	4,143,079	3,479,683
Interest expense	78,681,556	71,491,466
Total interest charges	82,824,635	74,971,149
NET INCOME	3,896,481	1,536,789
RETAINED EARNINGS—Beginning of year	10,342,251	8,805,462
RETAINED EARNINGS—End of year	$ 14,238,732	$ 10,342,251

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION
AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

	2018	2017
OPERATING ACTIVITIES:		
Net income	$ 3,896,481	$ 1,536,789
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	54,190,596	84,699,703
Amortization of debt expense	4,143,079	3,479,683
Loss (gain) on marketable securities	13,147,621	(6,998,135)
Changes in assets and liabilities:		
Accounts receivable	(23,544,559)	(3,290,823)
Fuel in storage	342,925	42,570,743
Materials and supplies	(2,189,366)	(3,588,135)
Property taxes applicable to future years	(150,000)	(90,000)
Emissions allowances	57,497	517,068
Income tax receivable	65,545	(3,476,610)
Prepaid expenses and other	(123,945)	(53,606)
Other regulatory assets	(1,146,702)	(4,215,734)
Other noncurrent assets	(1,244,103)	77,103
Accounts payable	10,589,698	(2,476,932)
Accrued taxes	(148,768)	940,223
Accrued interest and other	(5,021,649)	294,968
Decommissioning and demolition	3,076,062	-
Other liabilities	(10,203,483)	(20,444,880)
Other regulatory liabilities	43,646,969	52,091,672
Net cash provided by operating activities	89,383,898	141,573,097
INVESTING ACTIVITIES:		
Electric plant additions	(8,439,941)	(17,028,105)
Proceeds from sale of long-term investments	71,570,881	55,607,351
Purchases of long-term investments	(111,716,117)	(83,880,802)
Net cash used in investing activities	(48,585,177)	(45,301,556)
FINANCING ACTIVITIES:		
Debt issuance and maintenance costs	(529,670)	(11,308,531)
Repayment of Senior 2006 Notes	(20,798,412)	(19,636,354)
Repayment of Senior 2007 Notes	(14,759,418)	(13,920,909)
Repayment of Senior 2008 Notes	(15,926,263)	(14,926,913)
Redemption of 2009 Bonds	-	(25,000,000)
Proceeds from line of credit	-	50,000,000
Payments on line of credit	-	(50,000,000)
Principal payments under capital leases	(239,492)	(311,472)
Net cash (used in) provided by financing activities	(52,253,255)	(85,104,179)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(11,454,534)	11,167,362
CASH AND CASH EQUIVALENTS—Beginning of year	58,978,090	47,810,728
CASH AND CASH EQUIVALENTS—End of year	$ 47,523,556	$ 58,978,090
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 81,777,903	$ 72,541,166
Income taxes (received) paid—net	$ (74,784)	$ (2,912,531)
Noncash electric plant additions included in accounts payable at December 31	$ 892,150	$ 746,202

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 25% 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. 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, 2018 and 2017, were as follows:

	2018	2017
REGULATORY ASSETS:		
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	$ 4,147,956	$ 3,865,985
Unrecognized pension benefits	33,894,325	37,249,847
Asset retirement costs	8,721,689	4,501,436
Total	46,763,970	45,617,268
Total regulatory assets	$ 46,763,970	$ 45,617,268
REGULATORY LIABILITIES:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 6,024,309	$ 145,226
Deferred credit—advance collection of interest	1,633,482	1,764,244
Total	7,657,791	1,909,470
NONCURRENT REGULATORY LIABILITIES:		
Post retirement benefits	63,659,058	56,495,826
Income taxes refundable to customers	11,571,428	11,571,428
Advance billing of debt reserve	60,000,000	30,000,000
Decommissioning and demolition	2,818,822	3,823,282
Total	138,049,308	101,890,536
Total regulatory liabilities	$ 145,707,099	$ 103,800,006

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, 2018, 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 2019. 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 services.

The regulatory liability for postretirement benefits recorded at December 31, 2018 and 2017, 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 services as allowed under the ICPA. As of December 31, 2018 and 2017, $60 million and $30 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, less reserves for obsolescence. 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 post retirement 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 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 2018 and 2017 on securities still held at the balance sheet date were ($12,968,851) and $6,995,056, 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, 2017	$ 33,044,921
Accretion	1,941,140
Liabilities settled	(45,038)
Revisions to cash flows	22,229,597
Balance—December 31, 2017	57,170,620
Accretion	3,076,062
Liabilities settled	-
Revisions to cash flows	-
Balance—December 31, 2018	$ 60,246,682

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.

New Accounting Pronouncements—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 Jan. 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 two contracts with customers resulting in two types of revenue. These two contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
2) Sales of Electric Energy to Sponsoring Companies

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, 2018. 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	$40,734,337	$5,454,632
Ending balance as of December 31, 2018	64,278,896	5,098,515
Increase/(decrease)	$23,544,559	$ (356,117)

In January 2016, the FASB issued ASU 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, which revises an entity's accounting related to 1) the classification and measurement of investments in equity securities, 2) the presentation of certain fair value changes for financial liabilities measured at fair value, and 3) certain disclosure requirements associated with the fair value of financial instruments. The amendments require equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. However, an entity may choose to measure equity investments that do not have readily determinable fair values at cost minus impairment, if any, plus or minus changes as a result of an observable price change. For public business entities, the amendments 1) eliminate the requirement to disclose the method(s) and significant assumptions used to estimate fair value for financial instruments measured at amortized cost and 2) require, for disclosure purposes, the use of an exit price notion in the determination of the fair value of financial instruments. In February 2018, the FASB also issued ASU 2018-03 which makes technical corrections and improvements to the amendments in ASU 2016-01. The Companies adopted the amended guidance effective January 1, 2018. The adoption did not have an impact on the Companies consolidated financial statements, see Note 9, Fair Value Measurements.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*. The pronouncement provides specific guidance on eight cash flow classification issues to reduce the diversity in practice. The Companies adopted this standard effective January 1, 2018. The adoption of this standard did not have a material impact on the consolidated financial statements or Notes to the consolidated financial statements.

In March 2017, the FASB issued ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The pronouncement changes how defined benefit pension and other postretirement benefit plans present net periodic benefit costs. Under the new standard, the net periodic benefit cost will be included with other employee compensation costs whereas other components of the net periodic benefit cost will be disclosed separately outside of income from operations in the income statement. Additionally, on a prospective basis effective on the implementation date, only the service cost component of net periodic benefit cost are eligible for capitalization. The Companies adopted this standard effective January 1, 2018. As a result of adopting this standard, the Companies continue to present the service cost component of net periodic benefit cost within "Other operation" expense, however other components of the net periodic benefit cost are now presented separately within "Other Income Expense" in the Consolidated Statements of Income and Retained Earnings. There was no material impact to the financial statements for the years ended December 31, 2018 and 2017 as a result of the adoption of this standard.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which represents a wholesale change to lease accounting. The standard introduces a lessee model that brings most leases into the balance sheet as well as aligns certain underlying principles of the new lessor model with those in Accounting Standards Codification (ASC) 606, *Revenue From Contracts With Customers*. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842): Land Easements Practical Expedient for Transition to Topic 842*, which offers a practical expedient for accounting for land easements under ASU 2016-02. This practical expedient allows an entity the option of not evaluating existing land easements under ASC 842. New or modified land easements will still require evaluation under ASC 842 on a prospective basis beginning on the date of adoption. In August 2018, the FASB issued ASU 2018-11, *Leases (Topic 842): Targeted Improvements*, which allows entities the option to initially apply ASC 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Companies plan to adopt the new standard and all subsequent amendments in the fiscal year ending December 31, 2019. The Companies are in the process of evaluating the impact of adoption of this ASU on the Companies' consolidated financial statements.

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.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 11, 2019, which is the date the consolidated financial statements were issued.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2018 and 2017 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, 2018 and 2017, balances due from the Sponsoring Companies are as follows:

	2018	**2017**
Accounts receivable	$ 57,442,759	$ 39,005,995

During 2018 and 2017, 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, 2018. 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:

	2018	2017
General services	$ 4,917,608	$ 3,787,293
Specific projects	472,862	1,113,250
Total	$ 5,390,470	$ 4,900,543

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 2019 through 2022. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2019 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, 2018 are included in the table below:

2019	$239,702,109
2020	189,006,250
2021	160,365,000
2022	54,900,000

4. ELECTRIC PLANT

Electric plant at December 31, 2018 and 2017, consists of the following:

	2018	2017
Steam production plant	$ 2,690,743,500	$ 2,688,812,712
Transmission plant	81,578,790	81,190,947
General plant	12,917,451	12,843,389
Intangible	26,564	26,564
	2,785,266,305	2,782,873,612
Less accumulated depreciation	1,500,183,895	1,445,352,656
	1,285,082,410	1,337,520,956
Construction in progress	11,073,112	6,493,278
Total electric plant	$ 1,296,155,522	$ 1,344,014,234

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 has an unsecured bank revolving line of credit agreement with a borrowing limit of $200 million as of December 31, 2018 and 2017. The $200 million line of credit has an expiration date of November 14, 2019. At December 31, 2018 and 2017, OVEC had borrowed $85 million under this line of credit. Interest expense related to line of credit borrowings was $3,448,137 in 2018 and $2,680,713 in 2017. During 2018 and 2017, OVEC incurred annual commitment fees of $318,885 and $304,448, respectively, based on the borrowing limits of the line of credit. OVEC is expected to finalize a three-year extension of the agreement at a capacity of $185 million in April 2019.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2018 and 2017:

	Interest Rate Type	Interest Rate	2018	2017
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 189,381,919	$ 209,037,387
2006B due June 15, 2040	Fixed	6.40	55,360,136	56,503,080
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	84,386,325	93,609,630
2007A-B due February 15, 2026	Fixed	5.90	21,251,868	23,574,667
2007A-C due February 15, 2026	Fixed	5.90	21,421,088	23,762,382
2007B-A due June 15, 2040	Fixed	6.50	27,630,240	28,209,392
2007B-B due June 15, 2040	Fixed	6.50	6,958,404	7,104,257
2007B-C due June 15, 2040	Fixed	6.50	7,013,810	7,160,825
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	26,342,332	29,219,169
2008B due February 15, 2026	Fixed	6.71	53,467,070	59,238,453
2008C due February 15, 2026	Fixed	6.71	55,446,166	61,136,357
2008D due June 15, 2040	Fixed	6.91	40,230,351	41,017,439
2008E due June 15, 2040	Fixed	6.91	40,929,376	41,730,140
Series 2009 Bonds:				
2009B due February 1, 2026	Floating	3.19	25,000,000	25,000,000
2009C due February 1, 2026	Floating	3.19	25,000,000	25,000,000
2009D due February 1, 2026	Floating	1.41	25,000,000	25,000,000
2009E due October 1, 2019	Fixed	5.63	100,000,000	100,000,000
Series 2010 Bonds:				
2010A due February 1, 2040	Floating	6.06	50,000,000	50,000,000
2010B due February 1, 2040	Floating	3.19	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	6.06	50,000,000	50,000,000
2012C due June 1, 2040	Floating	6.06	50,000,000	50,000,000
Series 2017 Notes:				
2017A due August 4, 2022	Floating	6.06	100,000,000	100,000,000
Total debt			1,304,819,085	1,356,303,178
Total premiums and discounts (net)			(460,465)	(483,065)
Less unamortized debt expense			(14,618,729)	(18,038,611)
Total debt net of premiums, discounts, and unamortized debt expense			1,289,739,891	1,337,781,502
Current portion of long-term debt			179,670,116	76,483,805
Total long-term debt			$1,110,069,775	$1,261,297,697

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.

During 2009, OVEC issued a series of four $25 million variable-rate non-amortizing tax-exempt pollution control bonds (2009A, B, C, and D Bonds) and $100 million fixed-rate non-amortizing tax exempt pollution control bonds (2009E Bonds). The variable rates listed above reflect the interest rate in effect at December 31, 2018. The 2009E Bonds, which mature on October 1, 2019, are expected to be refinanced in 2019.

The 2009 Series D Bonds are secured by irrevocable transferable direct-pay letters of credit, expiring on November 14, 2019, issued for the benefit of the owners of the bonds. The interest rate on the bonds is adjusted weekly, and bondholders may require repurchase of the bonds at the time of such interest rate adjustments. OVEC has entered into an agreement to provide for the remarketing of the bonds if such repurchase is required. The 2009D Series Bonds are classified as current obligations, as they are redeemable at the election of the holders at any time. OVEC expects to refinance the 2009B Bonds or negotiate an extension to the current agreement in 2019. The 2009 Series B and C Bonds were remarketed in August 2016 for a five-year interest period that extends to August 25, 2021. The 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, and are being held by OVEC until refinanced.

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million remarketable variable-rate bonds due on February 1, 2040. In June 2011, the $100 million variable-rate bonds were issued as two $50 million non-amortizing pollution control revenue bonds (Series 2010A and 2010B) with initial interest periods of three years and five years, respectively. The Series 2010A Bond was remarketed in June 2014 for a three-year period and in August 2017 for another three-year period that extends to August 4, 2020. The Series 2010B Bond was remarketed in August 2016 for another five-year interest period that extends to August 25, 2021.

During 2012, OVEC issued $200 million fixed-rate tax-exempt midwestern disaster relief revenue bonds (2012A Bonds) and two series of $50 million variable-rate tax-exempt midwestern disaster relief revenue bonds (2012B and 2012C Bonds). The 2012A, 2012B, and 2012C Bonds will begin amortizing on June 1, 2027, to their respective maturity dates. The variable rates listed above reflect the interest rate in effect at December 31, 2018.

In 2017, the 2012B and 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). 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.

The annual maturities of long-term debt as of December 31, 2018, are as follows:

2019	$ 179,670,116
2020	141,387,803
2021	244,982,570
2022	148,800,891
2023	69,523,395
2024–2041	520,454,310
Total	$1,304,819,085

Note that the 2019 maturities of long-term debt include $25 million of remarketable variable rate bonds.

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:

	2018	2017
Income tax expense at statutory rate (21% 2018, 35% 2017)	$ 818,261	$ 537,876
Temporary differences flowed through to customer bills	(823,343)	(546,716)
Permanent differences and other	5,082	8,840
Income tax provision	$ -	$ -

Components of the income tax provision were as follows:

	2018	2017
Current income tax expense—federal	$ -	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	-	-
Total income tax provision	$ -	$ -

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.

On December 22, 2017, the United States Government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (TCJA). The TCJA made broad and complex changes to the Internal Revenue Code (IRC), many of which were effective on January 1, 2018, including, but not limited to, (1) reducing the federal corporate income tax rate from 35 percent to 21 percent, (2) eliminating the use of bonus depreciation for regulated utilities, while permitting full expensing of qualified property for non-regulated entities, (3) eliminating the domestic production activities deduction previously allowable under Section 199 of the IRC, (4) creating a new limitation on the deductibility of interest expense for non-regulated businesses, (5) eliminating the corporate Alternative Minimum Tax (AMT) and changing how existing AMT credits can be realized, and (6) restricting the deductibility of entertainment and lobbying-related expenses.

The TCJA eliminated the AMT after 2017. At December 31, 2017, the Companies had AMT credit carryforwards that do not expire. Pursuant to the TCJA, the Companies will be able to recover its alternative minimum tax carryforwards in future periods. The consolidated results reflect a net increase to refundable AMT tax credits and a corresponding increase in liability to Sponsor Companies of $6.1 million for the period ending December 31, 2017. AMT tax credits that are available as of December 31, 2017 will be refunded via annual tax filings through 2021.

TCJA also had an impact on the Companies by decreasing net deferred tax assets by $6.2 million, decreasing regulatory gross-up deferred tax asset by $9.1 million and a decreasing the valuation allowance for deferred tax assets by $15.3 million, excluding AMT tax credits as noted above. As the Companies have a full valuation allowance, the net impact on the balance sheet and income statement is zero. The movement in the accounts is related to the reduction in the federal corporate tax rate from 35% to 21%.

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. The regulatory liability was $11,571,428 at both December 31, 2018 and 2017.

Deferred income tax assets (liabilities) at December 31, 2018 and 2017, consisted of the following:

	2018	**2017**
Deferred tax assets:		
Deferred revenue—advances for construction	$ 1,265,885	$ 30,515
Federal net operating loss carryforwards	49,663,022	56,314,469
Postretirement benefit obligation	2,140,505	3,613,382
Pension liability	6,447,661	7,113,085
Postemployment benefit obligation	871,608	812,324
Asset retirement obligations	12,659,609	12,012,740
Advanced collection of interest and debt service	12,951,016	6,674,331
Miscellaneous accruals	1,183,464	1,284,013
Regulatory liability—postretirement benefits	13,376,650	11,870,952
Regulatory liability—income taxes refundable to customers	5,484,284	7,302,379
Total deferred tax assets	106,043,704	107,028,190
Deferred tax liabilities:		
Prepaid expenses	(352,638)	(360,396)
Electric plant	(81,674,810)	(77,669,885)
Unrealized gain/loss on marketable securities	(855,225)	(3,649,108)
Regulatory asset—pension benefits	(7,122,200)	(7,826,970)
Regulatory asset —asset retirement costs	(1,240,367)	(142,494)
Regulatory asset—unrecognized postemployment benefits	(871,608)	(812,324)
Total deferred tax liabilities	(92,116,848)	(90,461,177)
Valuation allowance	(13,926,856)	(16,567,013)
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, 2018 and 2017. 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 $4,614,682 and a non-current receivable of $4,614,683 for a total receivable of $9,229,365.

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, 2018 and 2017, 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 2014 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2014 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2013 and earlier. The Companies have $236,490,584 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 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2018, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2017.

The Pension Plan's assets as of December 31, 2018, 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	70

VEBA Plan Assets	**Target**
Domestic equity	20 %
International and global equity	20
Fixed income	57
Cash	3

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, 2018, 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, 2018 and 2017, are as follows:

	Pension Plan		**Other Postretirement Benefits**	
	2018	**2017**	**2018**	**2017**
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 256,019,423	$ 232,998,159	$ 168,487,209	$ 174,338,482
Service cost	7,108,309	6,511,513	4,297,973	5,100,383
Interest cost	9,445,262	9,796,123	6,196,344	7,434,498
Plan participants' contributions	-	-	1,363,566	1,357,889
Benefits paid	(10,240,977)	(11,928,458)	(5,270,543)	(6,175,593)
Net actuarial loss (gain)	(28,186,233)	18,676,940	(17,121,066)	(4,131,790)
Plan amendments (1)(2)	-	-	(6,648,237)	(9,436,660)
Expenses paid from assets	(46,647)	(34,854)	-	-
Projected benefit obligation—end of year	234,099,137	256,019,423	151,305,246	168,487,209
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	218,769,576	195,870,007	151,290,524	135,120,392
Actual return on plan assets	(14,277,140)	28,862,881	(6,304,997)	16,259,397
Expenses paid from assets	(46,647)	(34,854)	-	-
Employer contributions	6,000,000	6,000,000	40,099	4,728,439
Plan participants' contributions	-	-	1,363,566	1,357,889
Benefits paid	(10,240,977)	(11,928,458)	(5,270,543)	(6,175,593)
Fair value of plan assets—end of year	200,204,812	218,769,576	141,118,649	151,290,524
Underfunded status—end of year	$ (33,894,325)	$ (37,249,847)	$ (10,186,597)	$ (17,196,685)

(1) The $9.4M plan amendment is the result of the removal of a cost of living adjustment for non-grandfathered employees. These employees are expected to receive benefits through a Medicare Exchange with OVEC's maximum annual subsidy to be limited to $4,000.

(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.

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 $212,367,000 and $230,114,000 at December 31, 2018 and 2017, 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**	
	2018	**2017**	**2018**	**2017**
Service cost	$ 7,108,309	$ 6,511,513	$ 4,297,973	$ 5,100,383
Interest cost	9,445,262	9,796,123	6,196,344	7,434,498
Expected return on plan assets	(13,034,239)	(11,658,739)	(8,062,728)	(7,275,382)
Amortization of prior service cost	(416,565)	(416,565)	(2,536,062)	(1,763,901)
Recognized actuarial loss (gain)	1,049,337	1,049,964	-	-
Total benefit cost	$ 4,152,104	$ 5,282,296	$ (104,473)	$ 3,495,598
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 6,000,000	$ 6,000,000	$ -	$ -

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2018 and 2017:

	Fair Value Measurements at Reporting Date Using			
2018	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 7,138,880	$ -	$ -	$ 7,138,880
Equity mutual funds	35,494,238	-	-	35,494,238
Index futires	-	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
2017	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 9,089,309	$ -	$ -	$ 9,089,309
Equity mutual funds	43,799,989	-	-	43,799,989
Fixed-income securities	-	149,310,352	-	149,310,352
Cash equivalents	2,983,062	-	-	2,983,062
Subtotal Benefit Plan Assets	55,872,360	149,310,352	-	205,182,712
Investments measured at net asset value (NAV)				13,586,864
Total benefit plan assets				$ 218,769,576

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2018 and 2017:

	Fair Value Measurements at Reporting Date Using			
2018	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**2018 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
2017	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	55,419,961	-	-	55,419,961
Fixed-income mutual funds	69,687,330	-	-	69,687,330
Fixed-income securities	-	19,304,908	-	19,304,908
Cash equivalents	736,826	-	-	736,826
Benefit plan assets	$ 125,844,117	$ 19,304,908	$ -	145,149,025
Uncleared cash disbursements from benefits paid				(1,839,265)
Investments measured at net asset value (NAV)				7,980,764
Total benefit plan assets				$ 151,290,524

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, 2018 and 2017, were as follows:

Pension Plan		**Other Postretirement Benefits**			
2018	**2017**	**2018**		**2017**	
		Medical	**Life**	**Medical**	**Life**
4.40 %	3.75 %	4.40 %	4.40 %	3.76 %	3.76 %
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, 2018 and 2017, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2018	2017	2018		2017	
			Medical	Life	Medical	Life
Discount rate	3.75 %	4.31 %	3.76 %	3.76 %	4.31 %	4.31 %
Expected long-term return on plan assets	6.00	6.00	5.33	6.00	5.29	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, 2018 and 2017, were as follows:

	2018	2017
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	19.40	7.30
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	2,024	2,022

The high initial trend rate for age 65 and older benefits reflects the suspension of the employer health insurer tax for 2019. Currently, the suspension is only for one year so the 19.4% reflects typical trend plus the reinstatement of the health insurer tax. Subsequent to 2019, we expect a return to typical trend rates, with expected rates of 7.3%, 6.8%, 6.3%, 5.7% and 5.0% in 2020, 2021, 2022, 2023 and 2024, respectively.

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	$ 1,615,461	$ (1,581,454)
Effect on postretirement benefit obligation	19,356,216	(15,862,678)

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2018 and 2017, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2018	2017	2018	2017
Asset category:				
Equity securities	27 %	30 %	37 %	41 %
Debt securities	73	70	63	59

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,600,000 to their Pension Plan and $40,000 to their Other Postretirement Benefits plan in 2019.

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
2019	$ 9,977,333	$ 6,294,249
2020	10,834,783	7,061,898
2021	11,221,086	7,549,433
2022	12,051,740	8,149,404
2023	12,966,973	8,764,663
Five years thereafter	71,468,244	51,106,390

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 59% and 41% split between OVEC and IKEC, respectively, as of December 31, 2018, and approximately a 66% and 34% split between OVEC and IKEC, respectively, as of December 31, 2017. 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 $4,147,956 and $3,865,985 at December 31, 2018 and 2017, 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 2018 and 2017 were $2,014,215 and $1,997,840, 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, which was also used in 2018, was standardized to meet future ozone season compliance obligations as well.

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 SO_2 allowances in 2018 to cover actual emissions. The Companies also did not need to consume additional NO_x ozone season allowances purchased strategically in advance of the 2017 ozone season as a hedge to cover NO_x emissions in 2017 and beyond. Depending on a variety of operational and economic factors, management may elect to consume banked allowances and/or strategically purchase additional CSAPR annual and ozone season NO_x allowances in 2019 and beyond for compliance with the CSAPR Update rule.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available 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 in 2017 and 2018, 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 2018 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 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 its CCR units. Background results combined with the initial rounds of assessment monitoring indicate that there is a potential for groundwater quality issues with the boiler slag ponds at Kyger Creek Station and the landfill runoff collection pond at Clifty Creek Station. Alternative source demonstrations (ASD) are being completed in parallel to the additional groundwater evaluations. The Companies have determined that statistically significant increases (SSIs) in certain groundwater parameters are present at the two identified locations, and additional steps to determine next steps are underway. 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.

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. These 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, the U.S. EPA's announced plans to issue additional revisions to the CCR rule, and the D.C. Circuit Court's August 21, 2018 ruling vacating and remanding portions of the CCR rule. The Companies are actively monitoring these developments to ensure compliance obligations and timelines are adjusted accordingly.

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 40 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, the U.S. EPA entered into a settle agreement with the 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 our 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 the U.S. EPA as inconclusive. As a result, Kyger Creek installed a SO_2 monitoring network around the plant and is being required to monitor ambient air quality for at least a three-year window, which began on January 1, 2017. The U.S. EPA will then use the results of the monitoring network data to make a determination of compliance status with the SO_2 NAAQS by no later than December 31, 2020. Based on the first two years of data from that network, OVEC expects to show compliance with 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 NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid 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, was going to impact 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 intends to reevaluate what constitutes "best available technology" for these two wastewater discharges and issue an updated rule by no later than the fall of 2020. 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 would have most likely resulted in conversion of each plant's boiler slag ponds to either a closed-loop sluicing system or a dry handling 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. The study results are now on hold while the Companies await further regulatory action from U.S. EPA that will determine if these options are still appropriate or if other technology-based options will be available to demonstrate compliance. Until the new rulemaking is published associated with the ELG stay that would either change the scope or timeline for compliance, the Companies are still expected to complete engineering, design, construction, installation, and successful operation of all controls needed to demonstrate compliance with ELGs on these discharges by no later than December 31, 2023.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there was 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 for selenium and nitrate-nitrite nitrogen are now on hold while the Companies await further regulatory action from the U.S. EPA that will determine if the biological controls are still appropriate or if other technology-based options will be available to demonstrate compliance. Until the new rulemaking is published associated with the ELG stay that would either change the scope or timeline for compliance, the Companies are still expected to complete engineering, design, construction, installation, and successful operation of all controls needed to demonstrate compliance with ELGs on these discharges by no later than December 31, 2023.

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 intakes structures designed to withdraw at least 2 million gallons per day from waters of the U.S. and who also have an NPDES permit. The rule requires such facilities to 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).

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, 2018 and 2017, 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, 2018 and 2017, were as follows:

	Fair Value Measurements at Reporting Date Using		
2018	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ 64,095,224	$ -	$ -
Fixed-income mutual funds	22,186,437	-	-
Fixed-income municipal securities	-	93,085,184	-
Cash equivalents	1,904,689	-	-
Total fair value	$ 88,186,350	$ 93,085,184	$ -
2017			
Equity mutual funds	$ 49,400,226	$ -	$ -
Fixed-income mutual funds	10,246,444	-	-
Fixed-income municipal securities	-	90,140,833	-
Cash equivalents	4,486,457	-	-
Total fair value	$ 64,133,127	$ 90,140,833	$ -

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, 2018 and 2017, are as follows:

	2018		2017	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	$1,398,244,690	$1,329,819,085	$1,509,468,557	$1,381,303,178

11. LEASES

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

The amount in property under capital leases is $1,156,718 and $1,744,030 with accumulated depreciation of $464,194 and $908,732 as of December 31, 2018 and 2017, respectively.

Future minimum lease payments for capital and operating leases at December 31, 2018, are as follows:

Years Ending December 31	**Operating**	**Capital**
2019	$15,095	$224,821
2020	7,512	159,733
2021	-	96,392
2022	-	63,898
2023	-	55,121
Thereafter	-	160,769
Total future minimum lease payments	$22,607	760,734
Less estimated interest element		182,783
Estimated present value of future minimum lease payments		$577,951

The annual operating lease cost incurred was $34,218 and $36,610 for 2018 and 2017, respectively.

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 judgment" 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 Appeal"). The Sixth Circuit Appeal is currently pending, with oral arguments projected to be held in June 2019. On October 15, 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, 2018 on the consolidated balance sheets include receivables for FES' share of the Sponsor billings from March 2018 through December 31, 2018.

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