Docket No. 18-1542-EL-RDR

Compliance Audit of the 2018 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

Submitted on April 30, 2019

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Tables

DISCLAIMER

The word *audit* is intended, as it is commonly understood in the utility regulatory environment, to mean a regulatory review, a field investigation, or a means of determining the appropriateness of a financial presentation for regulatory purposes. It is not intended in its precise accounting sense as an examination of booked numbers and related source documents for financial reporting purposes. Neither is the term *audit* in this case an analysis of financial statement presentation in accordance with the standards established by the American Institute of Certified Public Accountants. The reader should distinguish regulatory reviews such as those that Blue Ridge performs from financial audits performed by independent certified public accountants.

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ORGANIZATION OF BLUE RIDGE'S REPORT

This report is organized according to the following major sections:

- *Executive Summary*: This section provides a summary of Blue Ridge's observations, findings, conclusions, and recommendations that are presented in more detail in the body of the report.
- *Summary of Blue Ridge Recommendations*: This section contains a listing of recommendations resulting from the 2018 Rider DCR audit.
- *Overview of Investigation*: This section includes discussion of these topics: background; project purpose; project scope; audit standard; information reviewed; description of the Rider DCR Compliance Filings reviewed; and a brief summary of the variance analyses, transactional testing, and other analyses.
- *Prior Compliance Audits Recommendations Status*: This section presents the current status of the Companies implementation of recommendations from prior DCR Rider audits.
- *Findings and Recommendations*: This section documents Blue Ridge's analysis that led to our observations, findings, and recommendations regarding the components that comprise Rider DCR. In several instances, Blue Ridge used information obtained from the prior audits of the Riders DCR in this report. The information used is labeled to show that it was obtained during the prior audits and is provided with the workpapers supporting this report.

The report also contains appendices.

Blue Ridge prefaced each scope area with the objective of the tasks planned to accomplish that area's review. The scope of the audit includes an overview of the process and control policies and procedures that affect the categories that feed into the Rider DCR calculations. A set of variance analyses reviews significant changes in net plant and reserve by individual FERC account.

The scope also includes review of each component of Rider DCR. The Rider DCR specific exclusions are addressed in the subsection labeled Riders LEX, EDR, AMI and General Exclusions, followed; gross plant in service; accumulated reserve for depreciation; accumulated deferred income taxes; depreciation expense; property tax expense; allocated Service Company; Commercial Activity Tax (CAT) and income taxes; the effect of the Tax Cuts and Jobs Act, and the return component. The report concludes with a review of the calculation of revenue requirements, followed by a review of the projections for the first quarter 2019.

EXECUTIVE SUMMARY

The FirstEnergy Service Company, on behalf of the three Ohio-regulated operating companies—The Cleveland Electric Illuminating Company (CE, CEI, or CECO), Ohio Edison Company (OE or OECO), and The Toledo Edison Company (TE or TECO), collectively referred to as "FirstEnergy" or "Companies"—prepared and submitted Compliance Filings regarding the Commission-approved Delivery Capital Recovery (DCR) Rider for actual plant in service through November 30, 2018, and estimated plant in service through February 28, 2019. Blue Ridge Consulting Services, Inc. ("Blue Ridge") was retained to perform a compliance audit of the filings.

BACKGROUND

Ohio's electric law, Senate Bill 221, requires electric utilities to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO), Section 4928.142 Revised Code, or an electric security plan (ESP), Section 4928.143 Revised Code. The Companies filed an application for approval of an ESP in Case No. 10-388-EL-SSO ("ESP II Case"). A majority of the parties in the case entered into an original stipulation and two supplemental stipulations (collectively, "Combined Stipulation"), and after a hearing, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order approving the Combined Stipulation in its entirety on August 25, 2010.

As part of its Opinion and Order, the Commission approved the establishment of the Rider DCR, effective January 1, 2012, to be updated and reconciled quarterly. The Opinion and Order allowed the Companies the opportunity to recover property taxes, Commercial Activity Tax, and associated income taxes, and to earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company, which was not included in the rate base determined in the Opinion and Order of January 21, 2009, in Case No. 07-551-EL-AIR (last rate case). On April 13, 2012, FirstEnergy filed an application for its next ESP, which was largely an extension of the Combined Stipulation, which the Commission approved with modifications on July 18, 2012, in Case No. 12-1230-EL-SSO ("ESP III Case"). The Rider DCR was extended with modifications by Order dated March 31, 2016, and reaffirmed on October 12, 2016, in Case No. 14-1297-EL-SSO ("ESP IV Case").

The Commission ordered an annual audit review of its Rider DCR for the purpose of determining whether the amounts for which recovery is sought are not unreasonable in light of the facts and circumstances known to the Companies at the time such expenditures were committed. The agreement also stipulated that, at the Commission's discretion, either an independent, third-party auditor or the Commission's Staff would conduct the annual audit review.

The Commission's Request for Proposal (RFP) sought proposals to audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR since the Companies' last Rider DCR Compliance Audit. Blue Ridge submitted a proposal and was selected to perform the 2018 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, 2015, 2016, and 2017 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2017).

PURPOSE OF PROJECT

As defined in the RFP, the purpose of the project included the following:

- Audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR with regard to the return earned on plant-in-service since the Companies' last Rider DCR Compliance Audit.
- Identify capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions to ensure they are excluded from Rider DCR.
- Identify, quantify, and explain any significant net plant increase within individual accounts.
- Assess the substantive implementation of the provisions contained within the Joint Stipulation and Recommendations filed in Case No. 14-1929-EL-RDR.

PROJECT SCOPE

The audit as defined in the RFP will address the following project scope:

> Determine if FirstEnergy has implemented its Commission-approved DCR Rider and is in compliance with the Combined Stipulation agreement set forth in Case No. 10-388-EL-SSO, as extended with modifications in Case No. 14-1297-EL-SSO.

As required by the RFP, Blue Ridge reviewed appropriate information associated with the stipulation and prior cases associated with the implementation of Rider DCR. During the course of the audit, Blue Ridge reviewed the compliance filings, developed transactional testing using statistically valid sampling techniques, and performed other analyses to allow Blue Ridge to determine whether the costs included in the Rider DCR were not unreasonable.

FINDINGS AND RECOMMENDATIONS

OVERALL IMPACT OF FINDINGS ON RIDER DCR REVENUE REQUIREMENTS

Blue Ridge's review found several items that have an impact on Rider DCR Revenue Requirements, including adjustments for plant recovered through other riders that were not excluded in the Companies' consolidated unitization process, vegetation management expenditures that should not be charged to plant, overstated plant balances due to delays or incorrect in-service dates or retirements not recorded timely, and failure to record a regulatory liability to reflect a refund of the excess deferred taxes owed to ratepayers because the Companies historically collected federal tax expense at 35% but will later pay the deferred portion to the federal government at 21%. The flow-through of these adjustments has the following impact on the DCR.

Table 1: Impact of Blue Ridge's Findings on Rider DCR Revenue Requirement

Adj #	Description	CEI	OE	TE	Total
	As Filed	**$ 156,274,362**	**$ 161,373,970**	**$ 40,236,054**	**$ 357,884,386**
1	EDR(g) Not Excluded (Consolidated Unitization)	(3,085)	-	-	(3,085)
2	Deleted		-	-	
3	LED Not Excluded (Consolidated Unitization)	165	33	(12,021)	(11,823)
4	Vegetation Mgmt-Expense	(1,786,623)	(1,141,265)	(364,336)	(3,292,224)
5, 6	Wrong In-Service Date, AFUDC Overstated	-	(37,042)	-	(37,042)
7	Retirements Not Recorded Timely	-	(4,312)	-	(4,312)
8	Delay in Closing, AFUDC Overstated	-	(3,227)	-	(3,227)
9	EDIT Regulatory Liability	(20,849,697)	(23,547,507)	(6,257,130)	(50,654,334)
	Impact of All Adjustments	**(22,639,240)**	**(24,733,321)**	**(6,633,488)**	**(54,006,048)**
	Recommended Rider DCR Revenue Requirements	**$ 133,635,123**	**$ 136,640,649**	**$ 33,602,566**	**$ 303,878,338**

PROCESSES AND CONTROLS

Blue Ridge was able to obtain an understanding of the Companies' processes and controls that affect each of the categories within Rider DCR. Furthermore, we were satisfied with actions taken with regard to internal audits and the process and control of the prior Rider DCR recommendations.

Based on information reviewed, Blue Ridge concluded that, except for the recommendations regarding vegetation management, the Companies' controls were adequate and not unreasonable.

Blue Ridge believes that the Companies' vegetation management (VM) policy is in conflict with FERC Uniform System of Accounts. Blue Ridge recommends that the Commission address and define VM capital and expense activity on a global basis for all electric utilities in Ohio to eliminate any bias on how VM costs should be recorded (capital versus expense) that is created based on how those costs are recovered. However, absent a Commission policy on the determination of capital and expense vegetation management activity, Blue Ridge recommends that the Companies revise their VM Accounting Policy to be consistent with the FERC Uniform System of Accounts. Also, in the absence of a Commission policy on the determination of capital and expense vegetation management activity, Blue Ridge recommends that Commission Staff undertake a periodic audit (review) of the Companies' vegetation management activities.

VARIANCE ANALYSIS

Examining the differences of account balances associated with Rider DCR calculations supports the determination of the trustworthiness of the DCR development.

In the current audit of the DCR year 2018, Blue Ridge evaluated several changes and variances in account balances:

- 2018 Plant Additions, Retirements, Transfers, and Adjustments
- Year-to-Year DCR Filing Plant-In-Service Balances
- Year-to-Year DCR Filing Reserve Balances
- Year-to-Year DCR Filing Service Company Balances
- End-of-year 2017 DCR Filing to 2017 FERC Form 1 Plant-in-Service Balances
- End-of-year 2018 DCR Filing to 2018 FERC Form 1 Plant-in-Service Balances
- 2018 Work Order Population totals to 2018 DCR Filing Year-to-Year Plant-In-Service Activity

The following table is a summary schedule of the net plant changes by classification of plant (i.e., Transmission, Distribution, General, and Intangible Plant). As this table shows, FirstEnergy's operating companies increased gross plant (including allocation of Service Company Plant) by $105.7 million, $107.7 million, and $29.1 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 3.4%, 3.1%, and 2.4% for CE, OE, and TE, respectively.

Table 2: Adjusted Plant Change from 11/30/2017 to 11/30/2018[1]

Line No.	Account Title	Adjusted Balance 11/30/17	Adjusted Balance 11/30/18	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 435,758,661	$ 441,091,992	$ 5,333,331	1.2%
3	Distribution	2,310,562,922	2,396,764,101	86,201,179	3.7%
4	General	162,226,119	166,712,292	4,486,173	2.8%
5	Other	62,828,422	67,738,056	4,909,634	7.8%
6	Service Company Allocated	100,737,744	105,485,068	4,747,324	4.7%
7	**Total Cleveland Electric Illuminating Company**	**$ 3,072,113,868**	**$ 3,177,791,510**	**$ 105,677,642**	**3.4%**
8	**Ohio Edison Company**				
9	Transmission	$ 214,517,354	$ 215,061,249	$ 543,895	0.3%
10	Distribution	2,856,769,311	2,947,795,088	91,025,777	3.2%
11	General	189,827,704	194,594,576	4,766,872	2.5%
12	Other	90,743,432	96,387,122	5,643,690	6.2%
13	Service Company Allocated	122,076,281	127,829,195	5,752,914	4.7%
14	**Total Ohio Edison Company**	**$ 3,473,934,082**	**$ 3,581,667,230**	**$ 107,733,148**	**3.1%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,815,338	$ 23,644,382	$ 829,044	3.6%
17	Distribution	1,010,056,944	1,032,554,701	22,497,757	2.2%
18	General	74,842,863	75,936,254	1,093,391	1.5%
19	Other	28,912,125	31,029,618	2,117,493	7.3%
20	Service Company Allocated	53,736,249	56,268,600	2,532,351	4.7%
21	**Total Toledo Edison Company**	**$ 1,190,363,519**	**$ 1,219,433,555**	**$ 29,070,036**	**2.4%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,736,411,469**	**$ 7,978,892,295**	**$ 242,480,826**	**3.1%**

FirstEnergy's responses regarding the variances in plant account balances were largely as a result of normal work order activity and are not uncommon among utilities. The changes in total plant balances for each of the Companies were not unreasonable.

RIDER LEX, EDR, AMI, AND GENERAL EXCLUSIONS

The Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL- SSO) requires that capital additions recovered through Commission-approved Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance.

Regarding Rider AMI, the Summary of Exclusion identifies only a portion of the AMI that is excluded from the DCR. Additional excluded amounts are found within the documentation that supports the DCR gross plant and reserve balances and reflect charges to various AMI Work Orders

[1] BRCS WP FE DCR CF Variance 2018– Confidential.xlsx, tab—PIS Summary.

that were identified during the 2013 Rider DCR Audit. Costs have continued to be recorded to these work orders since 2013. The Companies' reporting of AMI amounts excluded, supported by multiple sources, lacks transparency. Blue Ridge recommends that the Companies modify the reported Summary of Exclusions to reflect the AMI plant that is actually excluded.

The Companies use a consolidated unitization process to reduce its backlog of mass property work orders not unitized. When asked how the Companies ensured that plant associated with plant recovered through other riders in the consolidated unitization was identified and excluded from the DCR, the Companies stated that, on further review, it found an EDR work order ($16,621) and several Experimental Company-Owned LED Lighting Program work orders ($63,374) that should have been excluded from the DCR. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity been appropriately excluded.

The FERC accounts included in the consolidated unitization includes FERC accounts that are recovered through the DCR as well as through other riders. Therefore, we were unable to confirm that the consolidated unitization work orders identified and properly excluded costs that are recovered through other riders. Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through other riders is properly identified and excluded from the DCR.

GROSS PLANT IN SERVICE

The Rider DCR Compliance Filings include the following gross plant-in-service incremental change for each company from the time of the prior audit.

Table 3: Incremental Change in Gross Plant from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	3,072,113,869	3,177,791,509	105,677,640
Ohio Edison Company	3,473,934,081	3,581,667,230	107,733,149
The Toledo Edison Company	1,190,363,521	1,219,433,557	29,070,036
Total	7,736,411,471	7,978,892,296	242,480,826

Blue Ridge's review of gross plant through transactional testing of sample work orders had findings that affect the gross plant included in the Rider DCR. The impact of each of these findings is discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements section of this report.

Validation Testing from Sampled Work Orders

The Companies provided a list of work orders that support gross plant in service for December 2017 through November 2018. Blue Ridge selected a statistically valid sample of work orders (and added additional work orders using professional judgement) for detailed transactional testing.

For the most part, Blue Ridge found that observations and findings from the testing steps were met with justifications that proved to be not unreasonable. For example, budget versus actual costs yielded these findings:

39%—21 projects over budget greater than 15%
37%—20 projects were over/under budget by less than 15%
24%—13 projects did not have budgets (emergent work, accounting work orders, or storm work)

For most of the projects, the Companies' reasoning for each project's actual costs exceeding the budget was specific and unique to that project and not unreasonable. While a large percentage of projects that had budgets were over budget by greater than 15%, the Companies had completed implementation of the recommendations from the Audit of the Distribution Portfolio and Planning Process addressing that concern midway through 2018. Blue Ridge recommends that this issue be revisited in the next DCR audit to determine whether the recommendations were successful in reducing the percentage of projects coming in over budget.

Regarding cost detail in PowerPlant, some in-service dates were entered incorrectly resulting in over accrual of AFUDC. Blue Ridge has estimated the impact to the DCR revenue requirements and calculated an adjustment.

Blue Ridge also found that for assets retired, most work orders had appropriate cost of removal applied. Eleven work orders had cost of removal charged but no retirements. For most of those, the Companies' explanations were not unreasonable. For two, adjustments have been recommended. For one work order, the retirement will be completed when the work order is manually unitized. Blue Ridge recommended calculating the impact on depreciation and on the DCR when that retirement is completed.

Three retirement work orders did not have cost of removal charged, and one of those had an explanation that was not unreasonable. The other two will have an immaterial impact on the DCR.

Blue Ridge found that of the 21 work orders with estimated in-service dates, six had in-service dates that were over 90 days delayed from the estimates and were not closed in a reasonable time frame. For four of the projects, the Companies' explanations were not unreasonable. Two other work orders, however, resulted in over accrual of AFUDC and an overstatement of depreciation expense. Blue Ridge has estimated the impact to the DCR revenue requirement and included those adjustments.

Additionally, field verification for ten selected projects confirmed that the assets were installed and used and useful.

Vegetation Management

As noted in the Processes and Controls subsection above, Blue Ridge found the Companies' policy "Accounting for the Clearing of Transmission and Distribution Corridors" at odds with the FERC Uniform System of Accounts. As the discussion notes, we identified several cost categories that we believe are inappropriate to be charged to capital. Blue Ridge recommends that capital costs charged to Cost Category Codes 05, 36, 14, and 30 be excluded from Rider DCR as they do not meet the FERC Uniform System of Accounts definition of capital expenditures. Blue Ridge has calculated the impact to the DCR and has applied the appropriate adjustment.

Consolidated Unitization

Blue Ridge found that the Companies have made significant progress to reduce the unitization backlog. Total work orders in the backlog greater than 15 months were reduced by 53 percent from the end of 2017 to the end of 2018.

FirstEnergy explained that the backlog was reduced using a two-step process. First, mass property work orders with as-builts and labor and material charges were grouped and unitized en masse. Second, the remaining work orders were assigned to two full-time staff and one contractor who focused on the unitization in the fourth quarter of 2018.

Although the consolidations included mainly small dollar work orders representing mass property, due to the total dollars involved in the consolidation, Blue Ridge considered the potential ramifications of the Companies approach to yield these findings:

1) The consolidated unitization process can be summarized as follows: Once a project is completed and ready for service, it is moved from CWIP (FERC 107) to Completed Construction Not Classified (FERC 106). AFUDC accruals cease and depreciation is started based on the preliminary FERC 300 charge included in the estimate. The unitization process moves dollars from FERC 106 to Utility Plant in Service (FERC 101) and to the appropriate FERC 300 account. For reporting purposes, both FERC 106 and FERC 101 are considered plant in service.
2) Due to the volume of work orders included in the consolidated unitization, we were unable to confirm that the Companies' unitization resulted in the work orders being unitized to the proper FERC accounts. However, Blue Ridge does not believe that misclassification to the wrong FERC 300 account would be a significant concern as discussed below.
3) Assets were in-service prior to unitization and depreciation had already started. While there is a possibility that a project could be depreciated at the wrong depreciation accrual rate prior to unitization, the projects are, for the most part, individually small and the impact to the reserve would be minimal considering that any adjustment would only be for the incremental difference between one FERC 300 account rate and another.
4) Most Distribution utility projects are considered mass property (e.g., Poles, Overhead and Underground Line Conductors, Line Transformers and Meters). Mass property is depreciated by vintage year and not by individual asset.
5) Since retirements for mass property accounts are done on a curve, the impact to the reserve would be minimal.
6) Any over or under accrual of depreciation would be addressed in regular depreciation studies. The last depreciation study was performed using December 31, 2013, balances, and Blue Ridge recommends that a depreciation study be performed.[2]
7) While plant included in the consolidated unitization process may have been individually small dollars, the Companies process did not identify plant that is recovered through other riders to allow appropriate exclusion for the DCR. As discussed in the Exclusions section of the report, after further review, the Companies found EDR(g) and Experimental Company-Owned LED activity that should have been identified and excluded. While the amounts identified were not significant, it does raise concern about whether the consolidated unitization process could include other plant that should be excluded from the DCR. Blue Ridge recommends that the Companies review the charges reflected in the

[2] As part of the Stipulation in Case No. 16-481-EL-UNC, et al., p. 19 (filed 11/9/18), FirstEnergy has agreed to perform a Depreciation Study by June 30, 2023, with a date certain of December 31, 2022. This study would satisfy Blue Ridge's recommendation. However, the Stipulation still awaits Commission approval.

consolidated unitization to ensure that all plant recovered through other riders is properly identified and excluded from the DCR.

In conclusion, although there may be concern that some minimal amounts related to plant recovered in other riders were not properly identified and excluded from the DCR, Blue Ridge believes that the consolidation unitization process implemented by the Companies has no material effect on the DCR.

Insurance Recoveries

Insurance recoveries can reduce gross plant and should be taken into consideration in the calculation of the DCR. FirstEnergy stated that there were no insurance recoveries charged to capital for the Companies from December 1, 2017, through November 30, 2018.

ACCUMULATED RESERVE FOR DEPRECIATION

The Rider DCR Compliance Filings include the following accumulated reserve for depreciation ("reserve") incremental change from the prior audit for each company.

Table 4: Incremental Change in Reserve for Depreciation from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	(1,329,820,008)	(1,392,028,303)	(62,208,295)
Ohio Edison Company	(1,380,011,274)	(1,450,186,133)	(70,174,859)
The Toledo Edison Company	(604,078,268)	(633,339,860)	(29,261,593)
Total	(3,313,909,549)	(3,475,554,296)	(161,644,747)

As discussed in testing steps T1 through T10 above, Blue Ridge found adjustments that should be made to the reserve balances to ensure that net plant is appropriately reflected in the DCR. The specific adjustments are also discussed, as necessary, in the Exclusions and Gross Plant in Service subsections. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

ACCUMULATED DEFERRED INCOME TAXES

The Rider DCR Compliance Filings include the following accumulated deferred income taxes (ADIT) incremental change from the prior audits for each company.

Table 5: Incremental Change in ADIT from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	(502,293,445)	(246,517,542)	255,775,903
Ohio Edison Company	(609,321,744)	(307,470,479)	301,851,265
The Toledo Edison Company	(162,103,480)	(77,183,499)	84,919,982
Total	(1,273,718,669)	(631,171,519)	642,547,150

Blue Ridge found that the ADIT balances appropriately reflected the change in tax rates from the TCJA. The ADIT descriptions included were consistent with prior filings, were related to plant in service, and are not unreasonable. The Tax Cuts and Jobs Act Effects subsection of this report discusses the Companies' treatment of excess accumulated deferred income taxes (EDIT) arising from the Tax Cuts and Jobs Acts (TCJA).

DEPRECIATION EXPENSE

The Rider DCR Compliance Filings include incremental depreciation expense for each company from the prior audit as shown in the following table.

Table 6: Incremental Change in Depreciation Expense from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	99,292,700	102,103,616	2,810,917
Ohio Edison Company	104,903,818	106,951,437	2,047,619
The Toledo Edison Company	38,953,731	39,729,937	776,205
Total	243,150,250	248,784,991	5,634,741

Blue Ridge found that the calculation of depreciation expense was consistent with the methodology used in the last distribution rate case with the exception of FERC account 390.3 CEI and OE Actual. The Rider DCR uses gross plant-in-service balances consistent with the last distribution rate case to develop the depreciation expense component of the revenue requirements. Any revisions to gross plant should be flowed through the Rider DCR model to ensure that the appropriate amount of depreciation expense is included within the DCR.

The depreciation accrual rates used in the Rider DCR are based upon balances as of May 31, 2007. The Companies updated the depreciation study using plant as of December 31, 2013, and provided the updated study to the Commission Staff on June 1, 2015. Since the last depreciation study was based on balances from six years ago, Blue Ridge recommends that the Companies perform a deprecation study.[3] The study would also address any possible concerns associated with the over or under accrual related to the consolidated unitization process used by the Companies to reduce its unitization backlog.

PROPERTY TAX EXPENSE

The Rider DCR Compliance Filings include the following incremental property tax expense for each company from the prior audit.

Table 7: Incremental Change in Property Tax Expense from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	108,220,402	112,908,431	4,688,029
Ohio Edison Company	92,264,221	94,527,764	2,263,543
The Toledo Edison Company	30,860,390	31,477,071	616,682
Total	231,345,013	238,913,267	7,568,254

Blue Ridge found that the calculation of property tax is not unreasonable. As the Rider DCR uses plant-in-service balances to develop the property tax component of the revenue requirements, any

[3] As part of the Stipulation in Case No. 16-481-EL-UNC, et al., p. 19 (filed 11/9/18), FirstEnergy has agreed to perform a Depreciation Study by June 30, 2023, with a date certain of December 31, 2022. This study would satisfy Blue Ridge's recommendation. However, the Stipulation still awaits Commission approval.

revisions to gross plant should be flowed through the Rider DCR model to ensure the appropriate amount of property tax is included within the DCR.

SERVICE COMPANY

Blue Ridge found nothing that would indicate that Service Company costs included within Rider DCR are unreasonable.

COMMERCIAL ACTIVITY TAX AND INCOME TAXES

The Rider DCR Compliance Filings include the following incremental commercial activity tax (CAT) for each company. The CAT is calculated based on the statutory 0.26 percent.

Table 8: Incremental Change in CAT from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	313,900	399,040	85,140
Ohio Edison Company	324,396	408,510	84,114
The Toledo Edison Company	77,431	101,638	24,207
Total	715,728	909,189	193,461

The Rider DCR Compliance Filings include the following incremental income tax expense for each company.

Table 9: Incremental Change in Income Tax from 11/30/17 to 11/30/18

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	9,685,425	9,470,320	(215,105)
Ohio Edison Company	11,817,559	10,990,575	(826,984)
The Toledo Edison Company	1,136,850	1,844,768	707,918
Total	22,639,834	22,305,663	(334,171)

Blue Ridge found that the commercial activity tax and income tax expense were calculated consistent with prior filings and are not unreasonable. Any adjustments discussed in other subsections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

TAX CUTS AND JOBS ACT EFFECT

In the 2017 DCR Report, Blue Ridge expressed concerns regarding the Companies' treatment of excess accumulated deferred income taxes (EDIT) arising from the Tax Cuts and Jobs Acts (TCJA). Blue Ridge's concerns were addressed in a Stipulation that has not yet been approved by the Commission. The Stipulation allows for property EDIT balances, normalized and non-normalized, will be accounted for between the Rider DCR and credit mechanisms. Until this adjustment is made the DCR rate base is overstated. Thus, Blue Ridge recommends that the EDIT balances be reflected within the DCR and the overcollection due to the delay in recording the EDIT in the DCR be adjusted within the next DCR filing.

RETURN

The Rider DCR Compliance Filings include the following calculated return on rate base at 8.48% for each company.

Table 10: Incremental Change in Return on Rate Base from 11/30/17 to 11/30/18[4]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	28,183,288	53,560,482	25,377,194
Ohio Edison Company	34,828,839	63,612,126	28,783,288
The Toledo Edison Company	3,374,926	10,560,235	7,185,309
Total	66,387,052	127,732,843	61,345,791

Although the adjustments discussed in other subsections of this report will affect the final return included within the DCR, Blue Ridge found that the calculation of the return component of the DCR is not unreasonable.

RIDER DCR CALCULATION

The Compliance Filing Summary Schedules pull together the various components allowed within Rider DCR and calculate the revenue requirements based upon the actual November 30, 2018, and estimated February 28, 2019, balances. Although Blue Ridge found that the balances used in the Rider DCR calculations should be adjusted, Blue Ridge found that the Rider DCR calculation is not unreasonable.

The Annual Rider DCR Revenue through November 30, 2019, is under both the aggregate annual cap and the allocated annual cap by company.

PROJECTIONS

The Compliance Filings include projections for the first two months in 2019. To develop the first quarter 2019 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2019, the most recent (December 2018) forecast from PowerPlant. The estimated February 28, 2019, plant and reserve balances were then adjusted to reflect current assumptions (including project additions and delays), to incorporate recommendations from prior Rider DCR Audit Reports, and to remove the pre-2007 impact of a change in pension accounting.

Blue Ridge found that the projected amounts included through February 2018 are not unreasonable. In addition, the projected amounts will be reconciled to the actual amounts, and the Rider DCR revenue requirement will be adjusted to actual in the next quarter's Rider DCR Compliance Filings.

[4] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.

SUMMARY OF BLUE RIDGE RECOMMENDATIONS

For the 2018 Rider DCR assessment, Blue Ridge summarizes its recommendations as follows:

Rec-01. *Vegetation Management*: The Companies policy "Accounting for the Clearing of Transmission and Distribution Corridors" is in conflict with FERC accounting requirements, particularly in regard to certain capital-defined timesheet activity codes. Therefore, Blue Ridge recommends that the vegetation management costs charged to the DCR-associated with activity codes 05, 36, 14, and 30, be excluded from the DCR. (2018 DCR Report, pp. 46 and 67)

Rec-02. *Vegetation Management*: Because the vegetation throughout Ohio is similar in terms of geography and types of vegetation, to standardize treatment of vegetation management issues, Blue Ridge recommends that the Commission address and define vegetation management capital and expense activity on a global basis for all electric utilities in Ohio to eliminate any bias on how vegetation management costs should be recorded (capital versus expense) that may be created based on how those costs are recovered. (2018 DCR Report, p. 46)

Rec-03. *Vegetation Management*: Absent a Commission policy on the determination of capital and expense vegetation management activity (as suggested in Recommendation #2 above), and considering section 1.3 of the Companies' policy "Accounting for the Clearing of Transmission and Distribution Corridors" directs the capitalizing of FERC-defined maintenance work, Blue Ridge recommends that the Companies revise the specified policy to be consistent with the FERC Uniform System of Accounts. (2018 DCR Report, p. 46)

Rec-04. *Vegetation Management*: In the absence of a Commission policy on the determination of capital and expense vegetation management activity (as suggested in Recommendation #2 above), Blue Ridge recommends that Commission Staff undertake a periodic audit (review) of the Companies' vegetation management activities. (2018 DCR Report, p. 46)

Rec-05. *Internal Audits*: Regarding three internal audits in progress in 2018 regarding controls that would affect Rider DCR, Blue Ridge recommends that the results of the audits be reviewed in next year's DCR audit. (2018 DCR Report, p. 47)

Rec-06. *Economic Development Rider (Rider EDR(g))*: An EDR(g) recovered work order was not appropriately identified and excluded from the DCR during the consolidated unitization process. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity of EDR(g) work order 15204942 (cost $16,621) been appropriately excluded. (2018 DCR Report, p. 53)

Rec-07. *Advanced Metering Infrastructure Rider (Rider AMI)*: Due to the fact that the Summary of Exclusions within the DCR filings does not identify all the Rider AMI recovered plant that is excluded, in order to ensure transparency in the exclusion of AMI from the DCR, Blue Ridge recommends that the Companies modify the reported Summary of Exclusions to reflect the total amount of AMI plant that is actually excluded. (2018 DCR Report, pp. 55–56)

Rec-08. *Advanced Metering Infrastructure Rider (Rider AMI)*: Because of the Companies' use of multiple sources supporting the AMI exclusions, Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through the AMI Rider, including those work orders identified in the 2013 audit (separately identified) are properly identified and excluded from the DCR. (2018 DCR Report, pp. 56–57)

Rec-09. *Experimental Company-Owned LED Light Program*: Several Experimental Company-Owned LED Light Program work orders were not identified as such and thus excluded from the DCR during the consolidated unitization process. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity been appropriately excluded. (2018 DCR Report, p. 58)

Rec-10. *Experimental Company-Owned LED Light Program*: Because the Experimental Company-Owned LED Light Program includes FERC accounts that may be considered mass property and thus part of the consolidated unitization process, Blue Ridge was unable to confirm whether any additional LED costs (beyond those in regard to Recommendation #10 above) were included in the consolidated unitization work orders charged to the DCR. Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through Experimental Company-Owned LED lighting Program (and any other associated plant recovered through other riders) is properly identified and excluded from the DCR. (2018 DCR Report, pp. 58–59, 61, and 86)

Rec-11. *Projects over Budget Greater Than 15%*: While a large percentage of projects over budget raises a question about the Companies' planning process, the recommendations regarding such previous concerns were not fully implemented until midway through 2018. Therefore, Blue Ridge recommends that this issue be revisited in the next DCR audit to determine whether those 2018-implemented recommendations were successful in reducing the percentage of projects coming in over budget. (2018 DCR Report, pp. 73–74)

Rec-12. *In-service Dates Entered Incorrectly*: Two work orders had AFUDC that represented 35% of the total charges. Further investigation found that the in-service dates were entered incorrectly in PowerPlant and that AFUDC was over accrued. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the in-service dates for the work orders been entered correctly and AFUDC and not been over accrued. (2018 DCR Report, p. 74)

Rec-13. *Cost of Removal but No Retirements Charged*: Certain work orders had been completed but are still awaiting manual unitization at which time retirement will be charged (CECO WOs 14857540, CE-001312-DO-MSTM and OECO WOs 14370674, IF-OE-000127-1). Blue Ridge recommends that once the retirement is recorded, the Companies calculate the impact on depreciation and on the DCR. (2018 DCR Report, p. 76)

Rec-14. *Cost of Removal but No Retirements Charged*: For two OECO work orders (14777263 and OE-002814), the Companies explained the retirements occurred when the work orders were manually unitized, which was after November 30, 2018, and therefore not included in the DCR. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the retirements been recorded at the appropriate time. (2018 DCR Report, pp. 76–77)

Rec-15. *Actual In-Service Date Delayed from Estimate*: Two work orders (OECO IF-OE-000126 and IF-OE-000127) had delays of in-service dates resulting in over accrued AFUDC and overstatement of depreciation expense. Blue Ridge recommends that adjustments be made to change the in-service dates and to include reconciliations in the Rider DCR revenue requirement in a subsequent filing. (2018 DCR Report, pp. 79–80)

Rec-16. *Consolidated Unitizations*: Regarding the consolidated unitizations, any over or under accrual of depreciation would be addressed in regular depreciation studies. Since the last depreciation study for the Companies was performed using December 31, 2013, balances, Blue Ridge recommends that a depreciation study be performed. (As part of the Stipulation in Case No. 16-481-EL-UNC, et al., p. 19 [filed 11/9/18], FirstEnergy has agreed to perform a Depreciation Study by June 30, 2023, with a date certain of December 31, 2022. This study would satisfy Blue Ridge's recommendation. However, the Stipulation still awaits Commission approval.) (2018 DCR Report, pp. 86 and 91–92)

Rec-17. *Tax Cuts and Jobs Act Effect—EDIT Balances*: Based on the Stipulation and Recommendation filed in Case No. 18-1604-EL-UNC, treatment of property EDIT balances resulting from the TCJA, normalized and non-normalized, will be accounted for between the Rider DCR and credit mechanisms. Until the adjustment is made, the DCR rate base is overstated. Therefore, Blue Ridge recommends that the EDIT balances be reflected within the DCR and the overcollection due to the delay in recording the EDIT in the DCR be adjusted within the next DCR filing. (p. 99)

OVERVIEW OF INVESTIGATION

The FirstEnergy Service Company, on behalf of the three Ohio-regulated operating companies—The Cleveland Electric Illuminating Company (CE, CEI, or CECO), Ohio Edison Company (OE or OECO), and The Toledo Edison Company (TE or TECO), collectively referred to as "FirstEnergy" or "Companies"—prepared and submitted Compliance Filings regarding the Commission-approved Delivery Capital Recovery (DCR) Rider for actual plant in service through November 30, 2018, and estimated plant in service through February 28, 2019. Blue Ridge Consulting Services, Inc. ("Blue Ridge") was retained to perform a compliance audit of the filings.

BACKGROUND

Ohio's electric law, Senate Bill 221, requires electric utilities to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO), Section 4928.142 Revised Code, or an electric security plan (ESP), Section 4928.143 Revised Code. The Companies filed an application for approval of an ESP in Case No. 10-388-EL-SSO ("ESP II Case"). A majority of the parties in the case entered into an original stipulation and two supplemental stipulations (collectively, "Combined Stipulation"), and after a hearing, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order approving the Combined Stipulation in its entirety on August 25, 2010.

As part of its Opinion and Order, the Commission approved the establishment of the Rider DCR, effective January 1, 2012, to be updated and reconciled quarterly. The Opinion and Order allowed the Companies the opportunity to recover property taxes, Commercial Activity Tax, and associated income taxes, and to earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company, which was not included in the rate base determined in the Opinion and Order of January 21, 2009, in Case No. 07-551-EL-AIR (last rate case). On April 13, 2012, FirstEnergy filed an application for its next ESP, which was largely an extension of the Combined Stipulation, which the Commission approved with modifications on July 18, 2012, in Case No. 12-1230-EL-SSO ("ESP III Case"). The Rider DCR was extended with modifications by Order dated March 31, 2016, and reaffirmed on October 12, 2016, in Case No. 14-1297-EL-SSO ("ESP IV Case") through May 31, 2024.

The Commission ordered an annual audit review of its Rider DCR for the purpose of determining whether the amounts for which recovery is sought are not unreasonable in light of the facts and circumstances known to the Companies at the time such expenditures were committed. The agreement also stipulated that, at the Commission's discretion, either an independent third party auditor or the Commission's Staff would conduct the annual audit review.

The Commission's Request for Proposal (RFP) sought proposals to audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR since the Companies' last Rider DCR Compliance Audit. Blue Ridge submitted a proposal and was selected to perform the 2018 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, 2015, 2016, and 2017 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2017).

Excerpts of the Rider DCR provisions within the Opinion and Orders and Combined Stipulation are included within Appendix A. Appendix B contains a list of abbreviations and acronyms used within this report.

PURPOSE OF PROJECT

As defined in the RFP, the purpose of the project included the following:

- Audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR with regard to the return earned on plant-in-service since the Companies' last Rider DCR Compliance Audit.
- Identify capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions to ensure they are excluded from Rider DCR.
- Identify, quantify, and explain any significant net plant increase within individual accounts.
- Assess the substantive implementation of the provisions contained within the Joint Stipulation and Recommendations filed in Case No. 14-1929-EL-RDR.

PROJECT SCOPE

The audit as defined in the RFP will address the following project scope:

> Determine if FirstEnergy has implemented its Commission-approved DCR Rider and is in compliance with the Combined Stipulation agreement set forth in Case No. 10-388-EL-SSO, as extended with modifications in Case No. 14-1297-EL-SSO.

AUDIT STANDARD

Blue Ridge used the following standard during the course of the audit: "The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable. The determination of whether the amounts for which recovery is sought are not unreasonable shall be determined in light of the facts and circumstances known to the Companies at the time such expenditures were committed."[5]

INFORMATION REVIEWED

Blue Ridge reviewed the following information outlined in the RFP:

- Case Nos. 10-388-EL-SSO, 12-1230-EL-SSO, and 14-1297-EL-SSO and related stipulation agreements
- Case Nos. 11-5428-EL-RDR, 12-2855-EL-RDR, 13-2100-EL-RDR, 14-1929-EL-RDR, 15-1739-EL-RDR, 16-2041-EL-RDR, and 17-2009-EL-RDR Compliance Audit of the DCR Rider
- Applicable testimony and workpapers
- All additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred from December 1, 2017, through November 30, 2018. The information was included in the January 2, 2019, quarterly filings.
- Documentation related to compliance with Findings (22) in Commission's Finding and Order in Case Nos. 11-5428-EL-RDR, 12-2855-EL-RDR, 13-2100-EL-RDR, and contained in the Stipulation in Case No. 14-1929-EL-RDR.
- All appropriate documentation relating to the issues identified in the Auditor's Report in Case Nos. 11-15-1739-EL-RDR, 16-2041-EL-RDR, and 17-2009-EL-RDR to determine whether the

[5] Case No. 10-0388-EL-SSO Second Supplemental Stipulation, July 22, 2010, page 4.

issues raised have been addressed pursuant to the Auditor's recommendation, and if not, the impact of the Companies not addressing the identified concerns.

- Companies' actions taken to adjust the DCR for the changes in tax rates via the TCJA, including ADIT adjustments.

During the audit process, Blue Ridge requested and was provided additional information. A list of the data requested is included as Appendix C. Electronic copies of the information obtained was provided to Staff.

RIDER DCR COMPLIANCE FILINGS REVIEWED

On January 2, 2019, the Companies submitted various schedules, bill impacts, and tariff pages that provide the detailed calculations related to plant in service, accumulated depreciation reserve, income taxes, commercial activity taxes, property taxes, rate base, depreciation expense, and the resulting revenue requirement related to the Rider DCR (Compliance Filings) as contemplated by the Orders in the Companies' Case Nos. 10-388-EL-SSO, 12-1230-EL-SSO, and 14-1297-EL-SSO Electric Security Plan proceedings. These schedules included actual amounts through November 30, 2018, and projected balances for the three months ended February 28, 2019.

The following summarizes Rider DCR Revenue Requirements requested by each of the FirstEnergy operating companies.

Table 11: Rider DCR Revenue Requirements Actual 11/30/18 and Projected 2/28/19[6]

	Revenue Requirements		
Operating Company	**Actual 11/30/18**	**Projected 2/28/19**	**Total**
The Cleveland Electric Illuminating Company	$ 153,476,889	$ 2,797,473	$ 156,274,362
Ohio Edison Company	$ 157,119,414	$ 4,254,556	$ 161,373,970
The Toledo Edison Company	$ 39,091,649	$ 1,144,405	$ 40,236,054
Total	$ 349,687,952	$ 8,196,434	$ 357,884,386

VARIANCE ANALYSES, TRANSACTIONAL TESTING, AND OTHER ANALYSES

To identify, quantify, and explain any significant net plant increases within the individual accounts, Blue Ridge performed account variance analyses. The Companies were asked to explain any significant changes. The results of the analyses are included under the subsection labeled Variance Analysis.

In addition, Blue Ridge selected a sample of work orders from the population of work orders that support the gross plant in service for detailed transactional testing. The sample was selected using a statistically valid sampling technique. Additional work orders were selected based on professional judgment. The results of the transactional testing are included in the subsection labeled Gross Plant in Service.

Blue Ridge also performed various analyses, including mathematical verifications and source data validation, of the multitude of schedules that support the Rider DCR Compliance Filings. The

[6] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.

report addresses each component of the Rider DCR, and the results of these analyses are included within each component's subsection.

A list of Blue Ridge's workpapers is included in Appendix D. Electronic copies were provided to the Staff of the Public Utilities Commission of Ohio and the Companies.

PRIOR COMPLIANCE AUDITS RECOMMENDATIONS STATUS

Blue Ridge performed the Rider DCR compliance audit that covered capital additions from December 1, 2016, through November 30, 2017. Blue Ridge's report included several findings and recommendations and was filed in Case No. 17-2009-EL-RDR. The following list includes those recommendations. Following each recommendation is FirstEnergy's response regarding the recommendation's status[7] and Blue Ridge's associated comments based upon observations from this compliance audit.

a) Recommendation 1, 2017 DCR Report, p.42: To address Blue Ridge's concerns regarding the adequacy of the Companies' planning process in the 2016 audit, the Companies completed an internal audit with an objective to confirm that project management methodology and process design allows for projects to be fully scoped prior to project execution. The report issued on April 17, 2017, included several recommendations that are expected to be complete by June 2018. Blue Ridge recommends that, during next year's DCR audit, the auditor reviews whether the recommendations presented in the Audit of the Distribution Portfolio and Planning Process (April 17, 2018) were implemented.

   FirstEnergy Response: The Companies have implemented the recommendations from the Audit of the Distribution Portfolio and Planning Process.

   Blue Ridge's Comments: No additional work is necessary.

b) Recommendation 2, 2017 DCR Report, p. 42: Blue Ridge recommends implementation of the improvement opportunity identified in the Fleet Services audit: all FirstEnergy companies that benefit from fleet services, not just the utility companies, should be allocated the costs of Fleet Services costs since it is a shared services organization.

   FirstEnergy Response: The Companies have implemented this recommendation.

   Blue Ridge's Comments: FirstEnergy provided documentation showing the recommendation has been implemented. No additional work is necessary.

c) Recommendation 3, 2017 DCR Report, p. 42: In the internal audit FirstEnergy Utilities Major Storm Back Office Review Process, auditors recommended the Companies design and implement an invoice review process for less significant storms. Since the cost of storms, and their capital or expense designation, relates to the DCR process, Blue Ridge recommends that once an invoice review process has been implemented, it should be reviewed as part of the DCR audit process.

[7] All FirstEnergy status remarks are obtained from FirstEnergy's responses to Data Requests BRC Set 1-INT-10—Confidential.

FirstEnergy Response: The Companies have implemented the recommendation to design and implement an invoice review process for less significant storms. The process has been added to the FirstEnergy Utilities Emergency Preparedness Organization Checklist.

Blue Ridge's Comments: Blue Ridge reviewed the Proper Invoice Review and Approval Flow Chart. Blue Ridge examined the process and found it not unreasonable. No additional work is necessary.

d) Recommendation 4, 2017 DCR Report, p. 46: During Blue Ridge's evaluation of variances in regard to plant additions, retirements, adjustments, and transfers, the Companies' explanations for several adjustments were in regard to originally unitizing to the wrong utility account. The frequency with which this error occurred among semi-manually or manually addressed work orders leads Blue Ridge to recommend that the Companies' review its unitization process for work orders to determine whether additional control can be implemented to ensure more accurate recording.

FirstEnergy Response: The adjustments referenced in this recommendation related to Work Order 14164717 where Companies moved costs from general plant to distribution plant. Upon further investigation, the Companies have determined that this was a unique work order and occurrence. Thus, the Companies conclude that, at this time, additional controls are not necessary for its unitization process. The Companies will continue to monitor their process and implement any necessary controls.

Blue Ridge's Comments: Blue Ridge agrees with the Companies' characterization of the work order's unique occurrence. No additional work is necessary.

e) Recommendation 5, 2017 DCR Report, p. 51: During discovery regarding Rider EDR(g) exclusions, the Companies identified an error where $58,187 was included in FERC account 366 instead of FERC account 367. The Companies stated, and Blue Ridge recommends, it will include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the activity been appropriately included in FERC account 367.

FirstEnergy Response: The Companies' July 2, 2018, Rider DCR filing included an adjustment to incorporate the effect on revenue of the corrected EDR(g) balances.

Blue Ridge's Comments: Blue Ridge has reviewed and is satisfied with the Companies' provided support documentation.[8] No additional work is necessary.

f) Recommendation 6, 2017 DCR Report, p. 53: In its review of the incremental change in AMI plant in 2017 to the incremental change in Rider AMI costs excluded through the Rider DCR through November 30, 2017, Blue Ridge noted a significant difference. While there is a timing difference between the reporting periods, the difference is larger than can be explained through timing. Blue Ridge recommends that the Companies provide a reconciliation to document that there is no double recovery of AMI.

FirstEnergy Response: There is no double recovery of Rider AMI balances. The Rider AMI amounts included for recovery in the Companies' Rider AMI filings are based on capital

[8] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential

spend, whereas the amounts excluded from Rider DCR are plant in-service. The Companies appropriately exclude all AMI related balances from Rider DCR, though these exclusions are made in multiple areas of the filing and associated workpapers

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation. No additional work is necessary.

g) Recommendation 7, 2017 DCR Report, p. 55: During work order testing, costs associated with the Experimental Company Owned LED Lighting Program were discovered to be included in the Rider DCR that should have been excluded. These costs are recovered through the Experimental Company Owned LED Lighting Program rider. The Companies stated that the FirstEnergy-identified work order activity began to be removed with the April 3, 2017, Rider DCR filing. Costs incurred prior to that date had not been removed. FirstEnergy stated, and Blue Ridge recommends, that it will include a reconciliation in the Rider DCR revenue requirement in the next filing that incorporates the effect on revenues had the activity been appropriately excluded in the 2016 quarterly Rider DCR Compliance filings.

FirstEnergy Response: The Companies' July 2, 2018 Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to the Experimental Company Owned LED Lighting Program.

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation.[9] No additional work is necessary.

h) Recommendation 8, 2017 DCR Report, p. 55: Blue Ridge identified two riders other than LEX, EDR, and AMI that have the potential to include distribution plant. Blue Ridge recommends that future Rider DCR filings specifically review any distribution-plant-related costs recovered through the Government Directives Recovery Rider and the Experimental Company Owned LED Lighting Program to ensure that these two riders are excluded from the Rider DCR.

FirstEnergy Response: For the Government Directives Recovery Rider, there have not been any capital additions to date. As for the Experimental Company Owned LED Lighting Program, capital additions are included in a separate depreciation group that is excluded from Rider DCR.

Blue Ridge's Comments: No additional work is necessary.

i) Recommendation 9, 2017 DCR Report, p. 61: During the preparation of data responses during this audit, the Companies identified TECO work orders of $1,192,607 for the Toledo Edison Plaza Tenant Improvement project that should have been excluded from the Rider DCR. The Companies stated, and Blue Ridge recommends, that a reconciliation calculation be included in a future Rider DCR filing to reflect the cumulative revenue requirement impact of removing these costs.

[9] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential

FirstEnergy Response: The Companies' July 2, 2018 Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to the Toledo Plaza.

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation.[10] No additional work is necessary.

j) Recommendation 10, 2017 DCR Report, pp. 61–63: Blue Ridge believes that the Companies' policy Accounting for the Clearing of Transmission and Distribution Corridors, section 1.3, is in conflict with the FERC Uniform System of Accounts definition for FERC 365 and FERC 593 regarding what vegetation management costs should be capitalized and what costs should be recorded as a maintenance expense. First, the wording of the Companies' policy gives it broad leeway to remove any tree or limb outside a corridor for any reason and assign it as capital cost; thus, Blue Ridge recommends that the Companies' policy statement be better defined. Second, Blue Ridge recommends that the Companies revise its vegetation management policy in this area to be consistent with FERC definitions. Third, and as a result, Blue Ridge recommends that the three vegetation management work orders discovered in Blue Ridge's work order sample be excluded from the Rider DCR.

FirstEnergy Response: The Companies have continued to review their accounting policy subsequent to the recommendation and believe their policy is appropriate.

The Companies shape their capitalization policy from a number of salient factors, including but not limited to Generally Accepted Accounting Principles, management experience, insight from advisors, benchmarking industry peers, consideration of FERC Uniform System of Accounts, and review of other germane rules and regulations.

The GAAP, Handbook of Policies and Procedures states "expenditures incurred that increase the capacity, life or operating efficiency of a fixed asset are capitalized". The work contemplated in section 1.3 of the Companies' accounting guidance referenced in the DCR audit report includes initial clearing, widening of the corridor and subsequent removal. All of these activities increase the life of the conductors, so the costs are appropriately capitalized consistent with GAAP.

PwC audits FirstEnergy Corp.'s financial statements filed with the SEC on an annual and quarterly basis, which include the Companies' costs associated with the accounting guidance. See, for example, PwC's Report of Independent Registered Public Accounting Firm included in FirstEnergy Corp.'s 2017 10-K and annual report: "In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America."

The Companies have had discussions with other utilities, as well as EPRI and other entities, regarding the capitalization of these costs contemplated in the Companies' accounting guidance. These industry peers and experts have consistently agreed that the capitalization of these costs is appropriate and have supported the Companies' policy.

[10] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential

Blue Ridge's Comments: Blue Ridge disagrees with the Companies' response as noted below in discussing the Companies' four mentioned factors shaping their vegetation management (VM) capitalization policy:

- **Generally Accepted Accounting Principles (GAAP).** The Company produces financial statements in accordance with GAAP and FERC. For purposes of the DCR Utility Plant in Service and rate recovery, FERC (rather than GAAP and subject to PUCO approval) takes precedence. The Code of Federal Regulations (18 CFR) dictates what is capital and what should be considered expense. Blue Ridge does not disagree that "expenditures incurred that increase the capacity, life or operating efficiency of a fixed asset are capitalized," as mentioned in the GAAP Handbook of Policies and Procedures. However, the FERC code of accounts incorporates that consideration when retirement units of property are established. A retirement unit dictates what is capital and anything less than a retirement unit is expense. Minor items of property are capitalized initially and then expensed thereafter.

  For example, some utilities consider a fully dressed pole to be a unit of property. That would mean if a cross arm is replaced, it would be expensed. Other utilities consider a cross arm to be a retirement unit, and it is capitalized when replaced. The FERC code of accounts for FERC 365 and FERC 593 guide the accounting for VM and therefore the argument about GAAP is not relevant.

- **Management experience:** Employee experience is an invaluable tool in managing activities of a utility. However, that experience does not supersede FERC for how activities should be classified as capital or expense.
- **Insight from advisors and benchmarking industry peers:** The Companies have not done any recent distribution vegetation management benchmarking studies. Those studies that have been done are related to transmission. The Companies are part of an EEI vegetation-management task force but that group focuses on transmission with little focus on distribution.[11]
- **FERC Uniform System of Accounts and review of other germane rules and regulations.** The Companies are not following the FERC USofA regarding the capital/expense of vegetation management and have not indicated what other germane rules and regulations are followed.

Blue Ridge continues to recommend an adjustment should be made to the Rider DCR to remove the vegetation management costs that have been misclassified as capital. Further discussion of the Companies policies and Blue Ridge's analysis and recommendations is provided in the section identified as Tree Trimming and Clearing and Grading of Land.

k) Recommendation 11, 2017 DCR Report, p. 65—66: An emergent work order related to ATSI expenditures was found to have not been timely reimbursed, resulting in ATSI costs being recovered through the DCR. The Companies stated, and Blue Ridge recommends, that all

[11] Interview of Rebecca Spach—Director Vegetation Management on February 7, 2019.

necessary adjustments to the Companies' Rider DCR revenue requirements associated with this issue will be reflected in the reconciliation included in the next Rider DCR filing.

FirstEnergy Response: The Companies' July 2, 2018, Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to these ATSI expenditures.

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation.[12] No additional work is necessary.

l) Recommendation 12, 2017 DCR Report, pp. 71–72: During Blue Ridge's review of replacement work orders with associated asset retirement dates, two work orders had cost of removal recorded but had no retirements. The retirements had been passed to PowerPlant from CREWS, and the auto retirements processing failed. The errors were fixed in March 2018. The Companies stated, and Blue Ridge recommends, it will include a reconciliation in a future DCR filing to reflect the cumulative revenue requirement impact had the retirements not been delayed.

FirstEnergy Response: The Companies' July 2, 2018, Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to these replacement work orders.

Blue Ridge's Comments: Blue Ridge examined the Companies adjustments provided in response to our inquiry on the status of last year's recommendations[13] and is satisfied with the Companies' provided support documentation. No additional work is necessary.

m) Recommendation 13, 2017 DCR Report, p. 76: In regard to Blue Ridge's review of alignment of actual in-service dates with estimates, one project was found to have been delayed, and as a result, AFUDC was over accrued. Blue Ridge recommends adjustments to remove the excess AFUDC costs through a reconciliation in the Rider DCR revenue requirement in a future filing for this overstatement.

FirstEnergy Response: The Companies' July 2, 2018 Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to the removal of excess AFUDC costs.

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation.[14] No additional work is necessary.

n) Recommendation 14, 2017 DCR Report, p. 87: In regard to depreciation expense, it was found that most of the FERC accounts used gross plant (as opposed to net plant—gross plant less reserve for depreciation) in calculating depreciation expense, which it was determined was consistent with the methodology used in the last distribution base rate case. FERC account 390.3 Leasehold Improvements used net plant. Blue Ridge recommends that a reconciliation be included in the next DCR filing that incorporates the effect on Rider DCR

[12] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential.
[13] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential.
[14] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential.

revenue requirements had the depreciation expense for FERC account 390.3 been calculated based on net plant in service.

FirstEnergy Response: The Companies' July 2, 2018 Rider DCR filing included an adjustment to incorporate the effect on revenue of the exclusion of costs related to the correction in depreciation expense. The Companies' subsequent Rider DCR filings have calculated depreciation expense consistent with this recommendation.

Blue Ridge's Comments: Blue Ridge examined and is satisfied with the Companies' provided support documentation.[15] No additional work is necessary.

o) Recommendation 15, 2017 DCR Report, p. 78: Although the Companies have made progress reducing unitization backlog, totals remain above 2015 levels. Blue Ridge recommends that the Companies continue to make a concerted effort to reduce the volume of backlog work orders both in quantity and dollar value.

FirstEnergy Response: See responses to BRC Set 1-INT-029 and BRC Set 1-INT-030.

Blue Ridge's Comments: The Companies responses to the referenced data requests demonstrated that FirstEnergy did, in fact, reduce the volume of work orders both in quantity and dollar value.

p) Recommendation 16, 2017 DCR Report, p. 96: The Companies' estimated ADIT will need to be adjusted to reflect that bonus depreciation is no longer available to regulated public utilities. The Companies stated, and Blue Ridge recommends, that any impacts associated with bonus depreciation resulting from the federal income tax reform will be reconciled in the Companies' next Rider DCR filing.

FirstEnergy Response: In the April 2, 2018, Rider DCR filing, the Companies reconciled the estimated February 28, 2018 ADIT balances included in the January 12, 2018, Rider DCR filing with actual February 28, 2018, ADIT balances. These actual balances, and the balances in subsequent Rider DCR filings, did not include any ADIT associated with bonus depreciation resulting from the federal income tax reform.

Blue Ridge's Comments: Blue Ridge is satisfied with the Companies' response. No additional work is necessary.

q) Recommendation 17, 2017 DCR Report, pp. 94–98: Regarding the Tax Cuts and Jobs Act, Blue Ridge recommends (1) that the amount by which the ADIT balance is revalued is also the amount by which the Companies' must set up a regulatory liability to refund the excess deferred taxes to ratepayers because the tax future obligation to the federal government decreased by 40%, and (2) that the Companies apply the average rate assumption method (ARAM) consistent with normalization requirements to update the regulatory liability to address the timing differences for the property reversal. Additionally, the Companies reported in Case No. 18-0047-AU-COI that they filed updated Riders DMR and DCR to incorporate the impacts of the TJCA that resulted in annual customer savings equating to nearly $40 million. This statement does not comport with the $39,314,722 *increase* in customer rates in the Rider DCR, Blue Ridge recommends reconciliation of the Companies'

[15] FirstEnergy's response to Data Request BRC Set 1-INT-010, Attachment 2—Confidential.

reported annual Tax Act savings reflected in all riders. As an alternative to recording the regulatory liability with the Rider DCR ADIT balances, the Company should demonstrate that it reflected the regulatory liability in another filing.

FirstEnergy Response: The Companies' comments filed on February 15, 2018 in Case No. 18-47-AU-COI accurately stated the estimated annual savings from the TCJA on riders at the time. The nearly $40 million of annual savings was mainly attributed to Rider DMR. Although the Rider DCR revenue requirement increased from the January 2, 2018 Rider DCR filing to the January 12, 2018 Rider DCR filing, Rider DCR rates charged to customers did not increase due to the Commission approved Rider DCR revenue caps. As such, these statements in the Companies' comments do not conflict with the Companies' Rider DCR filing made January 12, 2018. On November 9, 2018, the Companies filed a Stipulation and Recommendation in Case No. 18-1604-EL-UNC ("Stipulation") which resolves the treatment of the excess deferred income tax balances resulting from the TCJA that was raised by Blue Ridge in the above recommendation. The Stipulation is pending Commission approval. The Companies will implement the Stipulation upon Commission approval.

Blue Ridge's Comments: Blue Ridge reviewed the pending Stipulation and found that it resolves the EDIT concerns raised by Blue Ridge. Once approved by the Commission, the property EDIT balances, normalized and non-normalized, will be accounted for between the Rider DCR and credit mechanisms. However, until this adjustment is made, the DCR rate base is overstated. Thus, as discussed in the section labeled Tax Cuts and Jobs Act Effect, Blue Ridge recommends that the EDIT balances be reflected within the DCR and the overcollection due to the delay in recording the EDIT in the DCR be adjusted within the next DCR filing.

FINDINGS AND RECOMMENDATIONS

Determine if the Companies implemented their Commission-approved DCR Rider and if the Companies are in compliance with the Combined Stipulation agreement set forth in the Opinion and Order issued in Case No. 10-388-EL-SSO and as extended with modifications in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO

The purpose of the audit is to determine whether the Companies implemented their Commission-approved Rider DCR and whether the Companies are in compliance with the Combined Stipulation agreement set forth in the Opinion and Order issued in Case No. 10-388-EL-SSO and as extended with modifications in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO. This section includes an overview of the process and control policies and procedures that affect the plant balances and expense categories that feed into the Rider DCR calculations. Various variance analyses review any significant changes in net plant by individual FERC account.

Each component of Rider DCR is investigated separately. The specific exclusions are addressed in Riders LEX, EDR, AMI, and General Exclusions and are followed by our analysis of gross plant in service; accumulated reserve for depreciation; accumulated deferred income taxes; depreciation expense; property tax expense; allocated Service Company; Commercial Activity Tax (CAT) and income taxes; and the return component. The report concludes with a review of the calculation of revenue requirements, followed by a review of the projections for the first quarter 2019.

Authority to Recover Components of Rider DCR

Blue Ridge reviewed the Commission Opinion and Order in Case No. 10-388-EL-SSO, dated August 25, 2010, the Combined Stipulation, and the Rider DCR relevant testimony and hearing transcripts. The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (as modified and reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO[16]) provide the authority for what should be included within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following items are to be included:

> Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant including allocated general plant from FirstEnergy Service Company that supports the Companies, which was not included in the rate base determined in the Opinion and Order of January 21, 2009 in Case No. 07-551-EL-AIR et al. ("last distribution rate case").[17]
>
> The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case.[18]
>
> The filing shall show the Plant in Service account balances and accumulated depreciation reserve balances compared to that approved in the last distribution rate case. The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case. Net capital additions for Plant in Service for General Plant shall be included in the DCR so long as there are no net job losses at the Companies as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. For each account title the Companies shall provide the plant in service and accumulated depreciation reserve for the period prior to the adjustment period as well as during the adjustment period. The filing shall also include a detailed calculation of the depreciation expense and accumulated depreciation impact as a result of the capital additions. The Companies will provide the information on an individual Company basis.[19]

[16] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10–11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[17] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[18] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[19] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 15.

PROCESSES AND CONTROLS

A. Review and update the processes and controls identified during the last audit that affect the costs in Rider DCR to validate that FirstEnergy exhibits reasonable management practices associated with the investment funded by Rider DCR
B. Determine if the Companies' cost controls related to the items under review are adequate and reasonable.

Blue Ridge did not perform a management audit but did review FirstEnergy's processes and controls to ensure that they were sufficient so as not to adversely affect the costs in Rider DCR. Beginning from a basis of last year's review of the 2017 FirstEnergy Rider DCR processes and controls, Blue Ridge reviewed documents relied upon for that audit, supplemented with changes to those processes and controls that the Companies have made since that audit. Based on the documents reviewed, Blue Ridge was able to update its understanding of the Companies' processes and controls that affect each of the plant balances and expense categories within Rider DCR. Blue Ridge concluded that FirstEnergy exhibits reasonable management practices associated with the investment funded by Rider DCR. Our only concern relates to vegetation management, discussed later in this section. Furthermore, by reviewing internal audit reports conducted on various areas of the Companies' operations, Blue Ridge found that the Companies' have processes in place to evaluate whether cost controls were adequate and that no significant internal control deficiencies were noted in the internal audits.

The following is a summary of the areas Blue Ridge reviewed.

Policies and Procedures

Blue Ridge reacquainted itself with the policies, procedures, and process flow diagrams associated with the various processes that affect the categories that feed into the Rider DCR calculations. Furthermore, we requested post-2017 modifications to those policies, procedures, and/or process flow diagrams to determine whether any concerns were raised in connection to the impact of those changes on the Rider DCR calculations. While the Companies stated that no significant changes to procedures or policies were incorporated in 2018, Blue Ridge specifically requested how the Companies addressed Accounting Standards Update (ASU) No. 2017-07 that limited the components of net periodic pension and postretirement benefit costs that are eligible for capitalization. Based on the Companies response, Blue Ridge concluded the Companies have appropriately adopted the update.

The policies, procedures, and process flow diagrams reviewed related to the following areas:

1. Plant Account
    a. Capitalization
    b. Preparation and approval of work orders
    c. Recording of CWIP including the systems that feed the CWIP trial balance
    d. Application of AFUDC
    e. Recording and closing of additions, retirements, cost of removal, and salvage in plant
    f. Unitization process based on the retirement unit catalog
    g. Application of depreciation
    h. Contributions in Aid of Construction (CIAC)

2. Purchasing/Procurement
3. Accounts Payable/Disbursements
4. Accounting/Journal Entries
5. Payroll (direct charged and allocated to plant)
6. Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)
7. Insurance Recovery
8. Property Taxes
9. Service Company Allocations
10. Budgeting/Projections
11. IT Projects

As a result of our review, Blue Ridge notes the following regarding processes that affect the Rider DCR.

Capitalization (1.a above); Plant Assets, including CWIP, Unitization, and Depreciation (1.c, 1.e, 1.f, 1.g); Accounting Entries, including Accounts Payable and Payroll (3, 4, 5)[20]

The Companies regard Capitalization as the procedure by which the total value of a capital asset of specified qualifications is assigned to its Balance Sheet classification of "Property, Plant and Equipment." This value is expensed to the Income Statement over its expected life by means of depreciation expense. Specifically, the Capitalization policy states, "Costs which result in additions or improvements of a permanent character which add value to the property shall be capitalized if a) the useful life is greater than one year and b) costs are greater than $1,000 (excluding computer software). Computer software shall be capitalized for costs greater than $5,000. . . . All other costs shall be expensed."[21]

The Capitalization Policy also holds the relevant policies for plant additions, retirements, removal cost, and salvage applicable to Rider DCR. The policy provides the qualifications for capital additions, which include extensions, enlargements, expansions, or replacements made to an existing asset. Once an asset is capitalized, the Companies track it using the Continuing Property Records (CPR). This CPR is a PowerPlant[22] ledger that contains a full audit trail for all plant transactions (additions, retirements, adjustments, inter and intra company transfers, etc.). Retirements (classified as such according to specific criteria) are accounted for by crediting their original cost to its plant account. The Retirement Unit Catalog is a listing within PowerPlant of all retirement units. Based on a specific set of criteria, these units are identified as retirement units to differentiate between replacements or additions chargeable to plant accounts (capital) and those chargeable to maintenance accounts (expense).

Construction work in process (CWIP) is the account to which capitalized costs are charged during the construction phase. Following construction, when the asset is ready to be placed into

[20] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy—Confidential.
[21] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy—Confidential.
[22] "PowerPlant" is a commercially available computer software application used in plant accounting.

service, the cost is transferred to the completed construction not classified account (CCNC). Finally, after unitization, the asset is transferred to electric plant in service (EPIS).

FirstEnergy had no significant procedural or policy changes in regard to the capitalization policy in 2018.[23]

Preparation and Approval of Work Orders[24]

Blue Ridge had reviewed both the Work Management Process flow diagram as well as the CREWS (Customer Request Work Scheduling System) Work Request Type Narratives. Elements such as project size and contractor involvement affect the process for managing the work. According to the CR (Customer Request) in the CREWS name, the system would seemingly include only work specifically initiated by request of customers. However, the system does include routine preventive and corrective maintenance as well.

The CREWS Work Request Type Narratives categorize work based on area (e.g., Distribution, Forestry, Meter, Substation) and then by more specific activity within those categories.

FirstEnergy did not significantly modify this process for the Companies in 2018.[25]

Contributions in Aid of Construction (CIAC)[26]

Regarding Contributions in Aid of Construction, Blue Ridge had examined the Companies' Invoicing Process Flow Chart that follows work initiation, authorization, scheduling, and completion in accordance with funding—invoicing, payment, and recording.

FirstEnergy did not significantly modify this process for the Companies in 2018.[27]

Application of AFUDC[28]

FirstEnergy has a policy in place to account for capitalized financing costs during construction. Three conditions must be met: (1) expenditures for the asset must have been made; (2) activities necessary to prepare the asset for its intended use must be in progress; and (3) interest cost must be incurring. Interest capitalization ceases when any of these conditions ceases or, of course, when construction is complete.

[23] FirstEnergy's response to Data Request BRC Set 1-INT-012 and 013—Confidential.
[24] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, b, Attachment 1, Work Management Process—Confidential and WP FE response to 2011 audit Data Request BRC Set 1-INT-003, b, Attachment 2, CREWS Work Request Narratives—Confidential.
[25] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[26] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, e, Attachment 1, Invoicing Process Flow Chart—Confidential.
[27] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[28] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, d, Attachment 1, Accounting For Capitalized Financing Costs During Construction—Confidential.

FirstEnergy did not significantly modify this process for the Companies in 2018.[29]

Purchasing/Procurement[30]

Blue Ridge had reviewed FirstEnergy's procedure by which the Companies' Supply Chain prepares, reviews, approves, and processes procurement documents for all materials, equipment, and services. The procedure applies to all business units and operating companies within FirstEnergy. The procedure identifies minimum requirements, exceptions, responsibilities, and actual process steps. Process steps include justifications, requisitions, approvals, buyer activity, sourcing strategy, bidding process, award, execution, and order maintenance.

FirstEnergy did not significantly modify this process for the Companies in 2018.[31]

Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)[32]

In its Accounting for Income Taxes procedure, the Companies stated that tax reporting and disclosing of both current and future income taxes in their financial statements is in accordance with generally accepted accounting principles.

FirstEnergy did not significantly modify this process for the Companies in 2018.[33]

Insurance Recovery[34]

According to the Companies, Insurance Risk Management (IRM) coordinates all large property and non-subrogation insurance recoveries. IRM oversees the process from notification to them by field personnel when an event occurs, through evaluation, claim, gathering of costs and expenses, and settlement, and finally culminating in ensuring proper accounting of recoveries.

FirstEnergy did not modify this process for the Companies in 2018.[35]

Property Taxes[36]

Blue Ridge examined the FirstEnergy desktop procedure for Ohio Property Tax returns. The procedure addresses steps taken in producing property tax schedules.

FirstEnergy did not modify this process for the Companies in 2018.[37]

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[29] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[30] WP FE response to 2016 audit Data Request BRC Set 1-INT-013, b, including Attachment 3, Procedure for Enterprise Sourcing of Materials and Services—Confidential.
[31] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[32] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, m, Attachment 1, Income Tax Policy and Procedure—Confidential.
[33] FirstEnergy's response to Data Request BRC 1-INT-012—Confidential.
[34] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a—Confidential.
[35] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[36] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, n, Attachment 1, Ohio Property Tax Returns—Confidential.
[37] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.

Service Company Allocations[38]

According to the Stipulation in Case 10-388-EL-SSO and continued in Case No. 12-1230-EL-SSO and Case No. 14-1297-EL-SSO, expenditures reflected in the quarterly filing will be "broken down by the Plant in Service Accounts Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case."[39] The most recent base distribution rate case is Case No. 07-0551-EL-AIR. There were no changes to these allocation factors for the Companies in 2018.

Budgeting/Projections[40]

The Rider DCR Compliance Filings include three months of projected data through the end of February 2019. The estimate is based on the most recent (December 2018) forecast from PowerPlant adjusted to reflect current assumptions, to incorporate recommendations from prior audits, and to remove the cumulative pre-2007 impact of a change in pension accounting.[41] Blue Ridge had reviewed the Companies' capital budget process to understand whether that process was sound and results in reasonable projections of expected capital expenditures that would be included in the Rider DCR. Blue Ridge had sought to understand the Companies' processes and practices for justifying and approving the capital funds that would be expended on FirstEnergy's transmission, distribution, general, and intangible gross plant. The policies, procedures, and process flow diagrams showing key controls related to, among other things, capital budgeting and projections had been reviewed. Blue Ridge also had reviewed whether the cost controls were adequate and reasonable.

The budgeting activity of the Companies, with regard to its impact on Rider DCR, rests within a well-documented process flow. Capital Portfolio development and capital management highlight the process steps from business unit initiation, through decision points, and to the final consolidation and approvals necessary to complete the process. The Capital Planning cycle is aligned with the Integrated Business Planning calendar. The Capital Management Group guides the process, including entering the business units' settled capital target into the capital planning database, allowing the business units to structure their portfolios accordingly.

FirstEnergy's capital budgeting is known internally as "Multi-Year Enterprise Capital Portfolio."[42] Individual business unit programs drive the approval of the capital budgets at the business unit level.[43] In addition, the procedure for creating and acquiring approval for the capital

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[38] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[39] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 15.
[40] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio—Confidential; WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure—Confidential; and WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 3, Energy Delivery Capital Allocation Process—Confidential.
[41] DCR Filings: CE 12-30-16 DCR Filing.pdf, OE 12-30-16 DCR Filing.pdf, and TE 12-30-16 DCR Filing.pdf.
[42] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio—Confidential.
[43] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure—Confidential.

portfolio states, "Business Units will utilize internal review and approval processes to analyze and create a prioritized Capital Portfolio."[44]

In 2014, FirstEnergy implemented a new system to facilitate budget entry. This system, however, had no impact from a procedural or policy standpoint on developing budgets and projects.[45] Additionally, FirstEnergy made no significant procedural or policy change in 2018.[46]

Information Technology

FirstEnergy manages Information Technology (IT) projects through a formalized process. The process includes standardized templates to describe and manage the three basic management categories for IT projects: charter (establishment), scorecard (status, health, issues, and risks), and changes (through change requests). IT's Project Management Office meets biweekly to review IT projects. During these biweekly reviews, the scorecard is used to help track the actual spend on the projects relative to the original budget.

IT project cost definition begins with project estimates for labor and other-than-labor costs. These estimates become the initial budget for the project. The project manager controls the project's refinement as the project scope is finalized. The project manager manages this refinement through a change control process in which justification for changes (resource hours, cost, and schedule) must be provided and approvals for the changes must be received from senior IT management. While a requested change may be for a specific project, the review and approval process also takes into consideration any impacts on the overall portfolio for IT projects. If changes to an individual project are approved, FirstEnergy manages the project according to the new forecast (both cost and schedule).[47]

FirstEnergy did not modify this process for the Companies in 2018.[48]

Accounting Standards Update No. 2017-07 Compensation–Retirement Benefits

Accounting Standards Update (ASU) 2017-07 was issued in March 2017 with the intention of "[i]mproving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Costs."[49] Of specific potential impact to the DCR, the ASU limited the components of net periodic pension and postretirement benefit costs that are eligible for capitalization to only the service costs component. Previously, all components of net periodic pension and postretirement benefit costs (e.g., service cost, interest cost, expected return on plan assets) were eligible to be capitalized. The result of the accounting changes prescribed in ASU 2017-07 is that the portions of the costs that are no longer eligible to be capitalized increase the Companies' operating expenses as compared to prior accounting. Blue Ridge found that the Companies adopted ASU 2017-07 on January 1, 2018. Pension/OPEB non-service costs are no longer capitalized. The implementation was made effective by changing the overhead capitalization rates to zero. Prior to the change, the December 2017

[44] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Section C.2—Confidential.
[45] WP FE response to 2014 audit Data Request BRC Set 1-INT-015—Confidential.
[46] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[47] WP FE response to 2013 audit Data Request BRC Set 1-INT-032—Confidential.
[48] FirstEnergy's response to Data Request BRC Set 1-INT-012—Confidential.
[49] FASB Accounting Standards Update No. 2017-07.

targeted capitalization percentages for Pension/OPEB non-service costs were 60.99% for CEI, 62.84% for OE, and 58.46% for TE. These percentages were derived by the percentage of labor charged to the balance sheet as a percentage of total labor for each company based on the 2017 budget. No written policies or processes were updated. The Companies' response was not unreasonable. The update was reflected in the assets put into service during 2018 and included in the DCR.[50]

Development of Rider DCR Compliance Filings

The Rider DCR schedules are compiled and calculated using Microsoft Excel® spreadsheets by a Rates Analyst within the FirstEnergy Service Company's Rates and Regulatory Affairs Department. The Analyst coordinates the gathering of the data and performs the calculations and relies on the provider of the information for accuracy. The Rider DCR Compliance filings are comprised of a number of schedules. The schedules and information sources are summarized as follows:[51]

- Revenue Requirements Summary – calculated by the Rates Department
- DCR Revenue Requirement Calculation – gross plant, reserve, ADIT, depreciation, and property tax expense roll up from detailed schedules; commercial activity tax (CAT) and income tax rates are provided by the Tax Department; and revenue requirements are calculated by the Rates Department
- Plant in Service – Plant Accounting
- Reserve for Depreciation – Plant Accounting
- Accumulated Deferred Income Taxes (ADIT) Balances – Tax Department
- Depreciation Accrual Rates – Plant Accounting provides the gross plant balances; accrual rates are based upon the rates established in Case No. 07-551-EL-AIR, et al.
- Property Tax Calculations – Tax Department
- Summary of Exclusions – primarily from Plant Accounting
- Service Company Allocation Summary – gross plant, reserve, ADIT, depreciation and property tax expense roll up from detailed schedules; allocations are based upon last distribution rate case, Case No. 07-551-EL-AIR, et al.
- Service Company Depreciation Accrual Rates – rates are based upon the weighted average of the approved depreciation rates for the three Ohio Operating Companies
- Service Company Property Tax Rate – rates are based upon the weighted average of the property tax rates for the three Ohio Operating Companies; True Value Percentages & Capitalized Interest Workpaper – Tax Department
- Intangible Depreciation Expense – intangible plant balances provided by Plant Accounting; accrual rates are based on the last distribution rate case, Case No. 07-551-EL-AIR, et al.
- Rider DCR/Rate Design – the Case No. 10-388-EL-SSO Combined Stipulation provides the rate design for Rider DCR

[50] FirstEnergy's response to Data Request BRC Set 5-INT-007.
[51] Summary of the process repeats process as recorded in previous Rider DCR Compliance Audit Reports. See Compliance Audit of the 2011, 2012, 2013, 2014, 2015, 2016, and 2017 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

- Billing Units – Forecasting group in the Rates Department (The most recent forecast was used)
- Typical Bill Comparisons – prepared by the Rates Department to reflect the updated rates for Rider DCR
- Rider DCR Tariff – prepared by the Rates Department to reflect the updated rates for Rider DCR

After the Analyst prepares the Rider DCR schedules, they undergo a three-tiered review process. A peer Analyst completes the initial review. The Manager of Revenue Requirements (who is also trained to prepare the Rider DCR filings) and the Director of OH Rates and Regulatory Affairs complete reviews two and three prior to submission to the Commission. The Vice President of Rates and Regulatory Affairs reviews the filing as needed.

The description of this process largely parallels the process from previous years; however, FirstEnergy continues its ongoing effort to incorporate and track specific recommendations that come out of the previous years' Rider DCR audits.[52]

Tree Trimming and Clearing and Grading of Land

Policies regarding vegetation management (tree trimming and clearing and grading of land) are of importance in the DCR discussion because of the capital and expense accounting determination. The state of Ohio has adopted FERC accounting for regulatory purposes. Therefore, the determination of capital and expense should be in conformance with the Code of Federal Regulations (18CFR).

FERC Requirements

Regarding vegetation management (VM), the FERC Code of Federal Regulations (18 CFR), parts 101 to 142 define capital and expense in part as follows:

> **Capital:** FERC 365 (Overhead conductor and devices, part 9) The account shall include the cost of tree trimming initial cost, including the cost of permits.[53]
>
> **Maintenance:** FERC 593 (maintenance of overhead lines which deals with assets in FERC 365. Part k) This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services: trimming trees and clearing brush. (References operating expense instruction 2: Maintenance, part C, item 3: Work performed specifically for the purpose of preventing failure, restoring service ability, or maintaining life of plant.[54]

FirstEnergy Policy

The Companies stated that FirstEnergy management, in conjunction with their external auditors, developed and approved the policy Accounting for the Clearing of Transmission and Distribution

[52] FirstEnergy's response to Data Request BRC Set 1-INT-011.
[53] FERC Code of Federal Regulations (18 CFR), parts 101 to 142.
[54] FERC Code of Federal Regulations (18 CFR), parts 101 to 142.

Corridors ("VM Accounting Policy"). This policy establishes the means by which the Companies differentiate between capital and O&M activity:

1. CAPITALIZATION
   - 1.1. All expenditures associated with the initial clearing of transmission and distribution corridors shall be capitalized.
   - 1.2. Expenditures, such as removals, pruning, brush clearings, etc., associated with the initial widening of an existing corridor clearing zone shall be capitalized. Examples include:
     - 1.2.1. increasing initial distribution corridor clearing zones from 10 to 15 feet; and
     - 1.2.2. expanding the initial transmission clearing zone corridor.
   - 1.3. Expenditures associated with the subsequent removal of priority trees or other large tree limbs outside the corridor (where no future tree maintenance is required) shall be capitalized. The removal of tree limbs that overhang at a height 15 feet or more above conductors with voltages below 115 kv and which emanate from trees growing within the corridor shall be capitalized. If in the process of directionally pruning the overhang fifteen feet or higher, it becomes necessary to remove the entire tree, the tree removal cost shall be capitalized.
   - 1.4. Allowance for Funds Used During Construction shall not be applied to the subsequent removal of priority trees or large tree limbs.
2. EXPENSE
   - 2.1. Expenditures associated with the clearing or reclamation of an existing corridor clearing zone that are not capitalized in accordance with this policy shall be expensed. Such charges include:
     - 2.1.1. routine circuit maintenance,
     - 2.1.2. customer ticket work,
     - 2.1.3. clearing overgrown vegetation and overhang within the initial corridor clearing zone that are not capitalized under 1.2 above; and
     - 2.1.4. herbicide programs.[55]

Previous Analysis—Compliance Audit of the 2017 DCR Rider

In its compliance audit of the 2017 DCR Rider, Blue Ridge found the VM Accounting Policy to be in conflict with FERC regulation. Specifically, Blue Ridge noted the broad leeway under the Companies' policy section 1.3 to remove any tree or limb outside a corridor for any reason and assign it as capital cost. Blue Ridge recommended that the statement be better defined since the activity described was not done in conjunction with the initial or expansion work for a corridor, and therefore, appeared to be (according to FERC regulation) maintenance expense.

Furthermore, for trees within the corridor, the policy's section 1.3 directs the charge for limb and tree removal of trees overhanging 15 feet or more above distribution and sub-transmission

[55] WP FE response to 2017 audit Data Request BRC Set 9-INT-004 Confidential (FirstEnergy waived disclosure for purposes of this report).

conductors to capital even though it is not an activity of initial or expanded corridor clearing. Blue Ridge recommended the Companies revise their VM Accounting Policy to remove the conflict with FERC regulations.

Companies' Response to Previous Analysis

As part of the scope of the compliance audit of the 2018 DCR Rider, Blue Ridge requested status on the recommendations of the prior year's audit. In response to Blue Ridge's 2017 recommendations regarding the VM Accounting Policy, the Companies noted that the policy has been in effect since April 2008, and they believe their policy appropriate. They provide four factors that have shaped their VM Accounting Policy[56]:

1. *Generally Accepted Accounting Principles (GAAP)*—The Companies referred to the GAAP, Handbook of Policies and Procedures, which states in part, "Expenditures incurred that increase the capacity, life or operating efficiency of a fixed asset are capitalized." The Companies state that the work identified in the VM Accounting Policy as capital is consistent with the GAAP's definition. Furthermore, FirstEnergy's financial statements filed with the SEC, which include the impacts of the VM Accounting Policy, are audited by PwC on an annual and quarterly basis. PwC has consistently concluded that the reported results are in conformity with accounting principles generally accepted in the US.
2. *Management Experience*
3. *Insight from Advisors and Benchmarking Industry Peers*: The Companies state they have had several discussions with regional peer utilities' accounting staffs and audit teams regarding the policy. As part of their normal course of business, the Companies have also had similar discussions with EPRI. The Companies report that none of these peer utilities or EPRI expressed any disagreement with the Companies' policy. The Companies conclude that all these discussions and reviews support the appropriateness of the Companies' policy.
4. *FERC Uniform System of Accounts and review of other germane rules and regulations*

Current Analysis—Compliance Audit of the 2018 DCR Rider

Blue Ridge reviewed the Companies' responses to Blue Ridge's 2017 recommendation. While Blue Ridge agrees with the Companies that including GAAP, Management Experience, and Insight from Advisors and Industry Peers to shape policy is a good practice, our concern was limited to the conflict with FERC regulations. Differences exist between FERC Uniform System of Accounts (USoA) and GAAP because FERC information requirements and the informational needs of potential investors and creditors may not be the same in some instances.

PUCO Staff submitted a set of data requests to the Companies regarding their Tree Trimming Capitalization Policy. DR-002, part 2a, requested, "Explain how the policy of capitalizing this expense is in conformance with the FERC guidelines of what expenditures should be capitalized." The Companies responded,

> **FERC guidelines are not directly applicable as distribution vegetation management is not under FERC jurisdiction**. Management shapes its capitalization

[56] First Energy's responses to Data Requests BRC Set 1-INT-10, Rec-10, and Set 4-INT-001 Confidential.

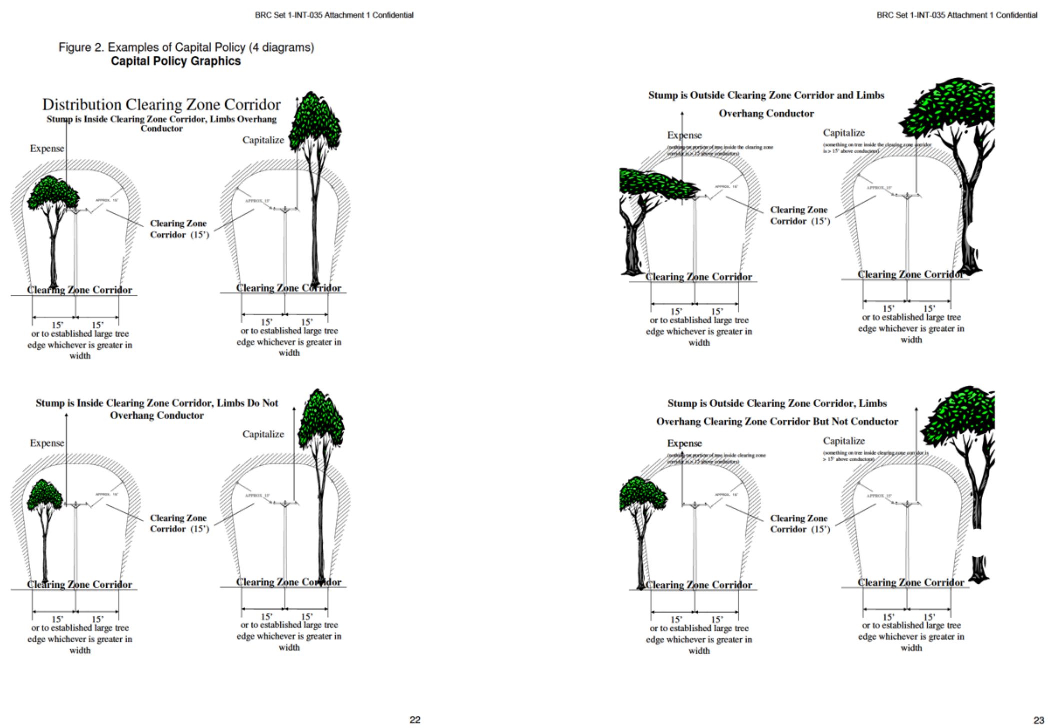
> policy from a number of salient factors, including but not limited to Generally Accepted Accounting Principles, management experience, insight from advisors, benchmarking industry peers, consideration of FERC Uniform System of Accounts, and review of other germane rules and regulations.[57] (emphasis added)

Blue Ridge disagrees. While FERC does not have jurisdiction over the distribution vegetation management *activity* of the Companies, PUCO does have jurisdiction regarding the Companies' ability to recover capital investments through the DCR and rate base. The state of Ohio has adopted FERC accounting for regulatory purposes. Therefore, the Companies must conform their accounting regarding capitalization to FERC accounting requirements for regulatory purposes. Adherence to GAAP standards, then, has no bearing on the discussion of whether the VM Accounting Policy is in conflict with FERC regulation.

In an effort to understand the Companies' position, Blue Ridge requested the specific guidance and/or instructions provided to field personnel enabling them to differentiate the capital or expense classification of routine vegetation work. The Companies provided the graphs below along with timesheet activity codes, specifying the kind of work being performed, that are used to record the costs as either capital or expense.

[57] FirstEnergy's response to Data Request Staff DR-002, 2.a, Confidential.

Figure 1: The Companies' Examples of Capital Policy[58]



The Companies also provided the activity codes given to field personnel that are used on timesheets. Several of the timesheet activity codes, related to off-corridor work, were identified as capital work. In a follow-up request, Blue Ridge asked for additional information on some of the codes. The Companies' explanations, particularly of codes 05 and 36, shed light on how the Companies viewed the work (emphasis added)[59]:

> **Code 05 Off corridor or removal of on corridor tree with overhang (identified as a capital item)**
>
> Code 05—The Capital illustrations on page 22 (top and bottom right) ***would be considered an expansion of existing corridor*** because the tree is greater than 15' above the conductors and would be designated Code 05 when entire tree is removed to a low stump height (typically stump left 3 inches tall).
>
> Code 05—All 4 illustrations on page 23 of Attachment 1 (trees are located off corridor) represent trees that ***would be considered an expansion of existing***

[58] FirstEnergy's response to Data Request BRC Set 1-INT-035, Attachment 1, Confidential (FirstEnergy waived disclosure for purposes of this report).
[59] FirstEnergy's response to Data Request BRC Set 5-INT-004, parts b and d, Confidential (FirstEnergy waived disclosure for purposes of this report).

corridor and designated Code 05 when entire tree is removed to a low stump height (typically stump left 3 inches tall).

Code 36 Cut Tree in the Clear Off Corridor No Future Maintenance Required (identified as a capital item)

Code 36—The Capital illustrations on page 22 (top and bottom right) represent trees that ***would be considered an expansion of existing corridor*** because the tree is greater than 15' above the conductors and would be designated Code 36 when the tree is removed only to the point that it will never threaten the electric facilities, no future maintenance required (typically stump left 15 to 20 ft tall).

Code 36—All 4 illustrations on page 23 of Attachment 1 (trees are located off corridor) represent trees that ***would be considered an expansion of existing corridor*** and designated Code 36 when the tree is removed only to the point that it will never threaten the electric facilities, no future maintenance required (typically stump left 15 to 20 ft tall).

Code 14 Overhang Limb Removal

Code 14—All 4 Capital illustrations of Attachment 1 represent work on limbs overhanging and ***outside the Clearing Zone Corridor*** that would be designated Code 14 when limbs are removed.

Code 30 Property Owner Notification Capital

Code 30—All work associated with customer notification for work designated as activities 05, 14, and 36.

Based on the highlighted portions in the code explanations, Blue Ridge understands that while the Companies define the clearing zone corridor as 15 feet in all directions (including above) from company facilities, permanently removing limbs or trees outside the corridor is considered an expansion of the corridor and should, therefore, according to the Companies, be capitalized. It is on this basis—subsequent clearing outside the corridor—that all four codes mentioned above (05, 36, 14, and 30) are charged to capital.

Blue Ridge disagrees with the Companies' definition of corridor expansion and, therefore with the charges to capital regarding subsequent clearing beyond the corridor. The size of the corridor should not fluctuate based on the subsequent growth of trees. According to the implication of the FERC regulation, once the standard corridor is cleared, all subsequent vegetation work should be charged as maintenance. We also found that the Companies' policies as written create an opportunity for bias in deciding whether costs should be recorded as capital or expense.

Conclusion—Tree Trimming and Clearing and Grading of Land

Blue Ridge recommends that the vegetation management costs charged to the DCR associated with the following codes be excluded from the DCR.

- Cost Category 05—Off Corridor or removal of on corridor tree with overhang
- Cost Category 36—Cut Tree in the Clear Off Corridor No Future Maintenance Required
- Cost Category 14—Overhead Limb Removal

- Cost Category 30—Property Owner Notification Capital

The Blue Ridge recommended adjustment is discussed in our work order testing criteria T1 summarized in the section labeled Project Testing,

The Companies have informed us that the vegetation throughout Ohio is similar in terms of geography and types of vegetation. Therefore, to standardize treatment of vegetation management issues, Blue Ridge recommends that the Commission address and define vegetation management capital and expense activity on a global basis for all electric utilities in Ohio to eliminate any bias on how VM costs should be recorded (capital versus expense) that may be created based on how those costs are recovered.

However, absent a Commission policy on the determination of capital and expense vegetation management activity and considering section 1.3 of the Companies' VM Accounting Policy directs the capitalizing of FERC-defined maintenance work, Blue Ridge recommends that the Companies revise their VM Accounting Policy to be consistent with the FERC Uniform System of Accounts.

The VM Accounting Policy and operating activities are administered at the operating company level. Each operating company is responsible for budgeting capital and expense, obtaining vendor bids, the types of contracts (time and material, unit price, etc.), administration of the policies and procedures, direction of operating activities, including vendor oversight, approval of time sheets, and payment of invoices. The Vegetation Management corporate organization has very little direct or functional responsibility over these activities. Therefore, in the absence of a Commission policy on the determination of capital and expense vegetation management activity, Blue Ridge recommends that Commission Staff undertake a periodic audit (review) of the Companies' vegetation management activities.

Internal Audit and SOX Compliance

Blue Ridge reviewed the list of 26 internal audits completed or in progress in 2018 regarding controls that would affect Rider DCR.[60] In particular, we examined and were satisfied with the findings and recommendations associated with the following 12 audits.[61]

1. Sarbannes-Oxley Annual Progress Report as of December 31, 2017.
2. Audit of Accounts Payable for the Year Ended December 31, 2017.
3. Sarbanes-Oxley 404 Assessment of Internal Controls Over Financial Reporting as of December 31, 2017
4. Audit of Distribution Portfolio Planning Process.
5. First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2018
6. Q2 2018 Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting
7. Tax Reform Deferral Accounting.
8. Q3 2018 Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting
9. Accounting for Capital and Maintenance costs.
10. IT Asset Management (in progress).

[60] FirstEnergy's response to Data Request BRC Set 1-INT-014, Attachment 1—Confidential.
[61] FirstEnergy's response to Data Request BRC Set 4-INT-007, Attachment 1—Confidential.

11. Pre-Implementation Review Operational Technology Configuration Management- Phase II (in-progress)
12. CREWS Modernization Pre-Implementation Review (in-progress).

Regarding the results of the first nine audits in the list, Blue Ridge is satisfied that for those audits in which findings or recommendations were suggested, the Companies have taken appropriate action. Blue Ridge recommends that the results of the last three audits on the list, which are currently ongoing, be reviewed in next year's audit.

Conclusion—Processes and Controls

Blue Ridge was able to obtain an understanding of the Companies' processes and controls that affect each of the categories within Rider DCR. Furthermore, we were satisfied with actions taken with regard to internal audits and the process and control of the prior Rider DCR recommendations.

Blue Ridge believes that the Companies' vegetation management policies and processes are in conflict with FERC Uniform System of Accounts. Blue Ridge recommends that the Commission address and define vegetation management capital and expense activity on a global basis for all electric utilities in Ohio to eliminate any bias on how VM costs should be recorded (capital versus expense) that is created based on how those costs are recovered. However, absent a Commission policy on the determination of capital and expense vegetation management activity, Blue Ridge recommends that the Companies revise their VM Accounting Policy to be consistent with the FERC Uniform System of Accounts. Also, in the absence of a Commission policy on the determination of capital and expense vegetation management activity, Blue Ridge recommends that Commission Staff undertake a periodic audit (review) of the Companies' vegetation management activities.

Based on information reviewed and except for the recommendations regarding vegetation management, Blue Ridge concludes that the Companies' controls were adequate and not unreasonable.

VARIANCE ANALYSIS

C. Perform a variance analysis to determine the reasonableness of any changes in plant in service balances including additions, retirements, transfers, and adjustments

Examining the differences of account balances associated with Rider DCR calculations supports the determination of the trustworthiness of the DCR development.

In the current audit of the DCR year 2018, Blue Ridge evaluated several changes and variances in account balances:

- 2018 Plant Additions, Retirements, Transfers, and Adjustments
- Year-to-Year DCR Filing Plant-In-Service Balances
- Year-to-Year DCR Filing Reserve Balances
- Year-to-Year DCR Filing Service Company Balances
- End-of-year 2017 DCR Filing to 2017 FERC Form 1 Plant-in-Service Balances
- End-of-year 2018 DCR Filing to 2018 FERC Form 1 Plant-in-Service Balances
- 2018 Work Order Population totals to 2018 DCR Filing Year-to-Year Plant-In-Service Activity

2018 Plant Additions, Retirements, Transfers, and Adjustments

Blue Ridge began its account variance analyses by examining the plant additions, retirements, transfers, and adjustments in order to understand changes to the unadjusted plant balances. In its investigation, Blue Ridge asked a multi-part data request regarding certain account changes of concern.

1. CEI Account 352 Structures and Improvements—Negative additions of $11,123
2. CEI Account 361 Structures and Improvements—Retirements of $0 although additions of $810,957
3. CEI Account 397 Communication equipment—Transfer/Adj of $358,449
4. OE Account 352 Structures and Improvements—Retirements of $0 although additions of $634,023
5. OE Account 360 Land and land rights—Negative Additions of $45,784
6. OE Account 391 Office furniture, equipment—Negative Additions of $30,619
7. OE Account 397 Communication equipment—Negative Adjustment of $239,534
8. TE Account 367 Underground conductors, devices—Negative Adjustment of $141,355
9. TE Account 368 Line transformers—Adjustment of $150,410
10. FESC Account 391 Office furniture, equipment—Retirements (greater than additions) of $16,181,476

FirstEnergy responded with requested account detail.[62] Our review of the detail, including understanding accounting entries and activity purposes, resulted in satisfaction that additions, retirements, transfers, and adjustments were not unreasonable.

Year-to-Year DCR Filing Plant-In-Service Balances

To support identifying, quantifying, and explaining any significant net plant increases within individual accounts, Blue Ridge compared Plant-in-Service account balances (FERC 300-series accounts) from DCR year-end November 30, 2017, with the year-end November 30, 2018, filing.

The following table is a summary schedule of the net plant changes by classification of plant (i.e., Transmission, Distribution, General, and Intangible Plant). As this table shows, FirstEnergy's operating companies increased gross plant (including allocation of Service Company Plant) by $105.7 million, $107.7 million, and $29.1 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 3.4%, 3.1%, and 2.4% for CE, OE, and TE, respectively.

[62] FirstEnergy's response to Data Request BRC Set 5-INT-008, with Attachments 1 through 1–10—Confidential.

Table 12: Adjusted Plant Change from 11/30/2017 to 11/30/2018[63]

Line No.	Account Title	Adjusted Balance 11/30/17	Adjusted Balance 11/30/18	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 435,758,661	$ 441,091,992	$ 5,333,331	1.2%
3	Distribution	2,310,562,922	2,396,764,101	86,201,179	3.7%
4	General	162,226,119	166,712,292	4,486,173	2.8%
5	Other	62,828,422	67,738,056	4,909,634	7.8%
6	Service Company Allocated	100,737,744	105,485,068	4,747,324	4.7%
7	**Total Cleveland Electric Illuminating Company**	**$ 3,072,113,868**	**$ 3,177,791,510**	**$ 105,677,642**	**3.4%**
8	**Ohio Edison Company**				
9	Transmission	$ 214,517,354	$ 215,061,249	$ 543,895	0.3%
10	Distribution	2,856,769,311	2,947,795,088	91,025,777	3.2%
11	General	189,827,704	194,594,576	4,766,872	2.5%
12	Other	90,743,432	96,387,122	5,643,690	6.2%
13	Service Company Allocated	122,076,281	127,829,195	5,752,914	4.7%
14	**Total Ohio Edison Company**	**$ 3,473,934,082**	**$ 3,581,667,230**	**$ 107,733,148**	**3.1%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,815,338	$ 23,644,382	$ 829,044	3.6%
17	Distribution	1,010,056,944	1,032,554,701	22,497,757	2.2%
18	General	74,842,863	75,936,254	1,093,391	1.5%
19	Other	28,912,125	31,029,618	2,117,493	7.3%
20	Service Company Allocated	53,736,249	56,268,600	2,532,351	4.7%
21	**Total Toledo Edison Company**	**$ 1,190,363,519**	**$ 1,219,433,555**	**$ 29,070,036**	**2.4%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,736,411,469**	**$ 7,978,892,295**	**$ 242,480,826**	**3.1%**

In our analysis of specific account variances from November 30, 2017, through November 30, 2018, Blue Ridge identified two accounts with significant change that would warrant further investigation.

1. CEI Account 393 Stores Equipment—Balance increase from $541,318 to $754,024 (39.3%)
2. OE Account 392 Transportation Equipment—Balance increase from $2,809,715 to $3,393,590 (20.8%)

FirstEnergy responded with requested detail.[64] Our review of the detail, including understanding accounting entries and activity purposes, resulted in satisfaction that the variances in question were not unreasonable.

[63] WP BRCS FE DCR CF Variance 2018– Confidential.xlsx, tab—PIS Summary.
[64] FirstEnergy's response to Data Request BRC Set 14-INT-001, with Attachments 1 and 2—Confidential.

Year-to-Year DCR Filing Reserve Balances

In our analysis of specific reserve account variances from November 30, 2017, through November 30, 2018, Blue Ridge submitted questions and received responses from FirstEnergy regarding two variances of concern among the three FirstEnergy operating companies:

1. Reserve OE Account 373 Street Lighting & Signal Systems: Balance decreased $1,229,053.
2. OE Account 392 Transportation Equipment: Balance increased $216,461

FirstEnergy responded with requested account detail.[65] Our review of the detail resulted in satisfaction that the variances in question were not unreasonable.

Year-to-Year DCR Filing Service Company Balances

Blue Ridge evaluated the change in Service Company balances through the evaluation of additions, retirements, transfers, and adjustments and through our work-order-testing activity discussed in the associated chapter of this report.

End-of-year 2017 DCR Filing to 2017 FERC Form 1 Plant-in-Service Balances

Blue Ridge received from FirstEnergy, during the 2017 DCR audit, a reconciliation between the 2017 plant-in-service account balances in the Companies' DCR Compliance Filings and their 2017 FERC Forms 1. Blue Ridge requested this reconciliation to ensure the DCR balances, with the appropriate adjustments, correctly correlated to what was reported on the FERC Forms 1. FirstEnergy provided a table comparing the balances and offering the explanations for the differences. After examination, Blue Ridge found the explanations not unreasonable and, with those explanations, found that the balances from the 2017 end-of-year DCR filings matched the balances of the 2017 FERC Forms 1, giving additional confidence that the beginning year DCR balances could be relied upon.[66]

End-of-year 2018 DCR Filing to 2018 FERC Form 1 Plant-in-Service Balances

Blue Ridge requested and received from FirstEnergy a reconciliation between the 2018 plant-in-service account balances in the Companies' DCR Compliance Filings and their 2018 FERC Forms 1. Blue Ridge requested this reconciliation to ensure the DCR balances, with the appropriate adjustments, correctly correlated to what was reported on the FERC Forms 1. FirstEnergy provided a table comparing the balances and offering the explanations for the differences. After examination, Blue Ridge found the explanations not unreasonable and, with those explanations, found that the balances from the 2018 end-of-year DCR filings matched the balances of the 2018 FERC Forms 1, giving additional confidence that the end year DCR balances could be relied upon.[67]

Work Order Population totals to DCR Filing Year-to-Year Plant-In-Service Activity

Blue Ridge compared the difference between the DCR November 30, 2018, gross plant balances and the November 30, 2017, gross plant balances for all Companies with the Work Order totals for the same period. For those accounts whose balances differed, Blue Ridge requested reconciliation

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[65] FirstEnergy's response to Data Request BRC Set 5-INT-009—Confidential.
[66] FirstEnergy's response to 2017 audit Data Request BRC Set 1-INT-007 and Attachment—Confidential.
[67] FirstEnergy's response to Data Request BRC Set 1-INT-007 and Attachment—Confidential.

from the Companies. The Companies provided the reconciliation, and Blue Ridge is satisfied that the compared balances match.[68]

Conclusion—Variance Analysis

FirstEnergy's responses regarding the variances in plant account balances were largely as a result of normal work order activity and are not uncommon among utilities. The changes in total plant balances for each of the Companies were not unreasonable.

RIDER LEX, EDR, AMI, AND GENERAL EXCLUSIONS

D. Determine if capital additions recovered through Riders LEX, EDR, and AMI have been identified and excluded from Rider DCR. Determine whether capital additions recovered through any other subsequent rider authorized by the Commission to recover delivery-related capital additions have been identified and excluded from Rider DCR

The Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO[69] and 14-1297-EL-SSO[70]) requires that capital additions recovered through Commission-approved Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance.[71]

The Schedule within the Rider DCR Compliance Filings labeled "Summary of Exclusions per Case No. 14-1297-EL-SSO" identifies the capital additions recovered through Riders LEX, EDR, and AMI, and other general adjustments that have been excluded from Rider DCR. The other general adjustments include exclusions for net plant related to land leased to ATSI, FirstEnergy's transmission subsidiary.

Line Extension Recovery Rider (Rider LEX)

Rider LEX includes deferred line extension costs during the period January 1, 2009, through December 31, 2011, including post-in-service carrying charges.[72]

The Companies' Rider DCR Compliance Filings state, "As implemented by the Companies, Rider LEX will recover deferred expenses associated with the lost up-front line extension payments from 2009–2011. These deferred expenses are recorded as a regulatory asset, not as plant in service on the Companies' books. Therefore, there is no adjustment to plant in service associated with Rider LEX."[73]

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include line extension work that should have been included in the Rider LEX. Blue Ridge found that the sample did not include any LEX work orders.[74]

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[68] FirstEnergy's response to Data Request BRC Set 9-INT-003 and Attachment—Confidential.
[69] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10–11.
[70] Case No. 14-1297-EL-SSO Commission Opinion and Order, March 31, 2016, page 119.
[71] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[72] Case No. 08-0935-EL-SSO Stipulation and Recommendation, Section B.3, page 16.
[73] CEI, OE, and TE Rider DCR Compliance Filings dated 1/12/19, page 19 and 44.
[74] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1b.

Economic Development Rider (Rider EDR(g))

Rider EDR(g) includes the cost of the electric utility plant, facilities, and equipment installed to reliably support the Cleveland Clinic Foundation's major expansion plans at its Main Campus located at 9500 Euclid Avenue in Cleveland, Ohio. Also included within the rider are the depreciation and taxes over a five-year period on a service-rendered basis, starting June 1, 2011.[75] FirstEnergy further stated that the capital additions associated with the Cleveland Clinic project recovered through Rider EDR(g) are excluded from Rider DCR pursuant to the ESP 2 Order in Case No. 10-388-SSO and continued in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO.

The Companies' Rider DCR Compliance Filings stated that the exclusions related to Rider EDR(g) are determined by the WBS CE-000303.[76] The Rider EDR(g) gross plant and reserve balances are shown separately in the Companies' workpapers to demonstrate that they are appropriately excluded from the balances that are recovered under Rider DCR. The incremental change from 2017 to 2018 in the amount of Rider EDR(g) excluded from Rider DCR is shown in the following table.[77]

Table 13: Incremental Change in Rider EDR(g) Exclusions from 2017 to 2018

Company	Actual 11/30/2017		Actual 11/30/2018		Change	
	Gross	Reserve	Gross	Reserve	Gross	Reserve
CEI	$ 247,748	$ 3,175	$ 167,355	$ 6,005	$ (80,394)	$ 2,830

The Companies explained that the $80,394 decline from November 30, 2017, to November 20, 2018, was primarily driven by CIAC charges or Overhead allocations.[78] The Companies' explanation is not unreasonable.

In contrast to the decline in the EDR(g) exclusion during the actual period ending November 30, 2018, the Companies are forecasting an increase in the forecasted period ending February 28, 2019, as shown in the following table.

Table 14: Incremental Change in Rider EDR(g) Exclusions from 11/30/2018 to 2/28/2019

Company	11/30/18		2/28/19		Difference	
	Gross Plant	Reserve	Gross Plant	Reserve	Gross Plant	Reserve
CEI	$ 167,355	$ 6,005	$ 189,203	$ 6,584	$ 21,849	$ 579

The Companies explained that the forecasted increase is for incidentals and make-right work associated with plant the Cleveland Clinic project. The Companies explained that if the estimated increases do not materialize, forecasted plant in service will be trued up in the subsequent Rider DCR filing, consistent with all Rider DCR filings.[79]

As discussed in the Work Order Backlog subsection, the Companies used a consolidated unitization process to reduce the backlog. When asked how they ensured that plant associated with

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[75] Case No. 10-0388-EL-SSO Stipulation and Recommendation, Section F.2, pages 27-28.
[76] CEI, OE, and TE Rider DCR Compliance Filings dated 1/2/2019, pages 19 and 44.
[77] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[78] FirstEnergy's response to 2018 Data Request BRC Set 7-INT-004.
[79] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-002.

the EDR included in the consolidated unitization[80] were identified and excluded from the DCR, the Companies stated that, upon further review, they found a work order, 15204942, with $16,621 of activity that should have been excluded.[81] The Companies stated (and Blue Ridge recommends) that they include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity been appropriately excluded.[82] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #1**].

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include work for the Cleveland Clinic Foundation. No work for the Cleveland Clinic Foundation was identified within the sample.[83] However, we did find Cleveland Clinic work orders in the work order population totaling $80,394. The Companies stated (and Blue Ridge confirmed) that these work orders are reflected in the November 30, 2018, plant balances but are identified as an exclusion and removed as the adjustments.[84]

Advanced Metering Infrastructure Rider (Rider AMI)

Rider AMI includes FirstEnergy's Smart Grid Modernization Initiative. Key components include distribution automation; voltage control; substation relay-based protection; alternate pricing programs; communications and data infrastructure; and data collection, analysis, and reporting.[85]

The Companies' Rider DCR Compliance Filings state that only CEI has an AMI project, so this exclusion does not affect OE or TE. Specific depreciation groups in PowerPlant and WBS CE-004000 determine exclusions related to Rider AMI.[86] The Rider AMI gross plant and reserve balances are shown separately in the Companies' workpapers to demonstrate that they are appropriately excluded from the balances that are recovered under Rider DCR.

The Summary of Exclusions in the Compliance filings lists the following amounts associated with Rider AMI that were excluded from Rider DCR.

[80] For further discussion of consolidated unitization, see the Work Order Backlog subsection of this report.
[81] FirstEnergy's response to 2018 Data Request BRC Set 15-INT-001.
[82] FirstEnergy's response to 2018 Data Request BRC Set 15-INT-001.
[83] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1c.
[84] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-005 Attachment 2, FE DCR Compliance Filing 1.2.2019—Confidential and WP List of EDR Workorders from 1-INT-002 CONFIDENTIAL.
[85] Case No. 09-1820-EL-ATA, et. al., Application pages 5–7.
[86] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-27.

Table 15: Rider AMI Gross Plant and Reserve Reported as Excluded from Rider DCR as of 11/30/2018

FERC Account	CEI	
	Gross	Reserve
303	$ (1,279,852)	$ (292,720)
362	5,384,748	2,257,238
364	163,082	66,199
365	1,801,510	1,152,779
367	11,080	4,363
368	185,568	118,285
370	16,821,526	8,628,263
397	4,730,254	2,136,239
Grand Total	$ 27,817,917	$ 14,070,645

The gross plant associated with AMI excluded from the DCR declined from the 2017 audit to the 2018 audit as shown in the following table.[87]

Table 16: Incremental Change in Rider AMI Exclusions from 2017 to 2018

Company	Actual 11/30/17		Actual 11/30/18		Change	
	Gross	Reserve	Gross	Reserve	Gross	Reserve
CEI	$ 28,287,943	$ 11,460,564	$ 27,817,917	$ 14,070,645	$ (470,026)	$ 2,610,082

The Companies explained (and Blue Ridge confirmed) that the reductions were due to accounting reversals and a decrease in retirements.[88] Blue Ridge found the Companies' explanation to be not unreasonable.

The Summary of Exclusion identifies only a portion of the AMI that is excluded from the DCR. In addition, to the charges shown in the table above, the DCR has the following AMI costs excluded as shown in the table below.[89] Of specific note, the highlighted FERC accounts are not reflected in the Summary of Exclusions. These additional excluded amounts are found within the documentation that supports the DCR gross plant and reserve balances and reflect charges to various AMI Work Orders that were identified during the 2013 Rider DCR Audit. Costs have continued to be recorded to these work orders since 2013.

[87] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[88] FirstEnergy's response to 2018 Data Request BRC Set 8-INT-008.
[89] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-001 Confidential.

Table 17: Additional Rider AMI Work Orders Identified in 2013 DCR Audit Excluded from the DCR

FERC Account	Accrual Rate	11/30/18		2/28/19	
		Gross Plant	Reserve	Gross Plant	Reserve
303 - Misc intangible plant	14.29%	$ (46,807)	$ 143,026	$ (46,807)	$ 151,931
303 - 2012 Software	14.29%	$ 2,328	$ 1,456	$ 2,328	$ 1,539
303 - 2013 Software	14.29%	$ 628,636	$ 393,016	$ 628,636	$ 415,474
352 - Structures and improvements	2.50%	$ 105,588	$ 11,549	$ 105,588	$ 12,209
353 - Station Equipment	1.80%	$ -	$ -	$ (1)	$ -
355 - Poles and fixtures	3.00%	$ (814)	$ (66)	$ (814)	$ (72)
356 - Overhead conductors, devices	2.78%	$ (447)	$ (43)	$ (447)	$ (46)
358 - Undergrd Conductor	2.00%	$ -	$ -	$ (1)	$ -
361 - Structures and improvements	2.50%	$ 478,108	$ 57,965	$ 478,108	$ 60,953
362 - Station equipment	1.80%	$ (720,916)	$ (34,402)	$ (720,922)	$ (37,646)
364 - Poles, towers and fixtures	4.65%	$ (4,814)	$ 33,841	$ (4,506)	$ 33,784
365 - Overhead conductors, devices	3.89%	$ 154,515	$ 153,465	$ 154,696	$ 156,926
367 - Undergrnd conductors, devices	2.44%	$ 1,762	$ 106	$ 1,915	$ 116
368 - Line transformers	2.91%	$ (377,856)	$ (88,552)	$ (377,842)	$ (91,301)
369 - Services	4.33%	$ 188	$ 31	$ 188	$ 33
370 - Meters	3.16%	$ 171,953	$ (82,004)	$ 171,952	$ (80,529)
373 - Street lighting,signal system	3.70%	$ 12,493	$ 2,937	$ 12,535	$ 3,053
391 - Office furniture, equipment	10.56%	$ 4,589,509	$ 1,830,015	$ 4,589,509	$ 1,929,928
397 - Communication equipment	7.50%	$ 2,006,204	$ 686,977	$ 2,006,204	$ 724,593
Grand Total		$ 6,999,631	$ 3,109,314	$ 7,000,320	$ 3,280,943

Highligthed FERC Accounts not reflected in Summary of Exclusions

Blue Ridge asked the Companies to reconcile the amounts recovered through the Rider AMI and the amounts excluded in the DCR. The Companies provided the following analysis:[90]

Table 18: Reconciliation of Amounts Recovered through Rider AMI and Amounts Excluded in DCR

#	Description	Plant In-Service	Accumulated Depreciation	Source
1	AMI Accumulated Spend Through 11/30/2018	$ 34,533,057	$ 14,476,359	2018 AMI Spend: Costs included in Rider AMI are based on spend and not plant in-service and are recovered over a ten year period as approved in Case No. 09-1821-EL-GRD.
2	Excluded From Rider DCR as of 11/30/2018	(27,817,917)	(14,070,645)	SGMI Depreciation Group balances as of 11/30/2018 excluded from Rider DCR as reported on page 19 of the Compliance Filings.
3	AMI in DCR Depreciation Groups Excluded from DCR as of 11/30/2018	(6,350,779)	(3,085,923)	AMI work orders that reside in Rider DCR depreciation groups, which are not included in (2). This information is contained in BRC Set 1 - INT-001 Attachment 4 Confidential in Case No. 18-1542-EL-RDR, which is the 2013 Rider DCR Audit Recommendations adjustment worksheet.
4	DCR in SGMI Depreciation Groups	(648,852)	(23,391)	DCR work orders that reside in AMI depreciation groups, which are not included in (2). This information is contained in BRC Set 1 - INT-001 Attachment 4 Confidential in Case No. 18-1542-EL-RDR, which is the 2013 Rider DCR Audit Recommendations adjustment worksheet.
5	Other	284,491	2,703,600	<u>Other Plant In-Service</u>: Includes Rider AMI spend that is removed from Rider AMI due to audit recommendations. For example $347,700, is excluded from Rider AMI Spend as required in Case No. 12-406-EL-RDR <u>Other Accumulated Depreciation</u>: Driven by timing differences between how AMI related costs are put into plant in-service versus how depreciation in Rider AMI is calculated based on spend
9	Sum (Lines 1-5)	$ -	$ -	

The Summary of Exclusions included on pages 19 and 44 of the DCR fillings states, "Consistent with prior ESPs, 'capital additions recovered through Riders LEX, EDR, and AMI will be identified and excluded from Rider DCR and the annual cap allowance' during EXP IV." However, as discussed above, the Summary of Exclusions within the DCR filings do not identify *all* the Rider AMI recovered plant that is excluded. The multiple sources supporting the exclusion of AMI in the DCR lacks transparency.

[90] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-007, Attachment 1 Confidential.

Blue Ridge recommends that the Companies modify the reported Summary of Exclusions to reflect the AMI plant that is actually excluded.

As part of Blue Ridge's work order sample testing, project descriptions were reviewed to ensure that the work orders included in the DCR did not include AMI-related work. Blue Ridge found several work orders with SmartGrid (SGMI) or AMI descriptions in the DCR population that were charged to utility account that were FERC account 391—Office Furniture, Equipment. Since the Summary of Exclusions included in the DCR does not include costs charged to Account 391, additional analysis was required to ensure proper treatment of these AMI-related costs.

- CECO – 996102 - SGIG Project Mgmt - VVC Line - $35,618 (charged to FERC 391)
- CECO – 996283 - DC Design - $120,397 (charged to FERC 391)
- CECO – CE-004000-SG-33 - SGMI Data Collection - $79,459 (charged to FERC 391)

Blue Ridge found that these AMI-related costs, while not shown on the Summary of Exclusions in the DCR revenue requirements filing, were excluded in the supporting documentation.

In addition, there were several SGMI or AMI charges in the work order population that were reclassified to FERC account 391—Office Furniture, Equipment.

Table 19: SGMI or AMI Workorders Reclassifications Included in the DCR

Company	FERC Plant Account	Work Order	Work Order Description	Type	Date	Total Activity
CECO	303 - Misc intangible plant	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	-$298,628
CECO	391 - Office furniture, equipment	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	$298,628
CECO	365 - Overhead conductors, devices	996277	AMI Closeout	Replacements	4/30/15	-$115,667
CECO	391 - Office furniture, equipment	996277	AMI Closeout	Additions	4/30/15	$115,667
CECO	365 - Overhead conductors, devices	CE-004000-SG-29	SGMI Data Integration	Replacements	6/1/15	-$102,824
CECO	391 - Office furniture, equipment	CE-004000-SG-29	SGMI Data Integration	Additions	6/1/15	$102,824

The Companies explained that the work was related to the Ohio Site Deployment of the Smart Grid Modernization Initiative, which is recovered through the Rider AMI. The work orders were reclassified during the review process associated with unitization to FERC account 391.2 Data Processing Equipment.[91] Blue Ridge requested the work order details for these work orders to confirm that it is appropriate to charge these AMI-related projects to 391.2-Data Processing Equipment and recover the costs through the DCR. Upon subsequent review, the Companies determined that all three of the work orders (991961—$298,628, 905277—$115,667, and CE 04000-SG-20—$102,824) are related to software and will be transferred to FERC 303—Misc Intangible plant.[92] Blue Ridge found the Companies explanation not unreasonable. These amounts are recovered through Rider AMI and have been excluded from the DCR.

Because of the Companies' use of multiple sources supporting the AMI exclusions, Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization[93] to

[91] FirstEnergy's response to 2018 Data Request BRC Set 4-INT-009.
[92] FirstEnergy's response to 2018 Data Request BRC Set 9-INT-001, a.
[93] For further discussion of consolidated unitization, see the Work Order Backlog subsection of this report.

ensure that all plant recovered through the AMI Rider, including those work orders identified in the 2013 audit that are separately identified, are properly identified and excluded from the DCR.

<u>*Other Riders*</u>

In addition to Riders LEX, EDR, and AMI, the Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO[94] and 14-1297-EL-SSO[95]) requires that capital additions recovered through any other subsequent rider authorized by the Commission to recover delivery-related capital additions be identified and excluded from Rider DCR and the annual cap allowance.[96] In addition to the Riders DCR, LEX, EDR, and AMI, the Companies' tariffs include the following riders:

1	Residential Distribution Credit	21	Non-Distribution Uncollectible
2	Transmission and Ancillary Service Rider	22	Experimental Real Time Pricing
3	Alternative Energy Resource	23	Experimental Critical Peak Pricing
4	School Distribution Credit	24	CEI Delta Revenue Recovery – CE
5	Business Distribution Credit	25	Experimental Company Owned LED Lighting Program
6	Hospital Net Energy Metering	26	Generation Service
7	Peak Time Rebate Program – CE	27	Demand Side Management and Energy Efficiency
8	Universal Service	28	Deferred Generation Cost Recovery
9	State kWh Tax	29	Deferred Fuel Cost Recovery
10	Net Energy Metering	30	Non-Market-Based Services
11	Grandfathered Contract – CE	31	Residential Deferred Distribution Cost Recovery
12	Delta Revenue Recovery	32	Non-Residential Deferred Distribution Cost Recovery
13	Demand Side Management	33	Residential Electric Heating Recovery
14	Reasonable Arrangement	34	Residential Generation Credit
15	Distribution Uncollectible	35	Phase-In Recovery
16	Economic Load Response Program	36	Distribution Modernization
17	Generation Cost Reconciliation	37	Government Directives Recovery Rider
18	Fuel	38	Ohio Renewable Resources Rider
19	Delivery Service Improvement	39	Commercial High Load Factor Experimental Time-of Use Rider
20	PIPP Uncollectible	40	Residential Critical Peak Pricing Rider

The Companies stated that the above riders should not include distribution capital additions or Service Company capital additions that are allocated to Rider DCR.[97] Blue Ridge reviewed the tariff for the above riders and found several riders that have the potential to include costs that could also be recovered through the Rider DCR: Experimental Company Owned LED Light Program, Government Directive Recovery Rider (Rider GDR), and Distribution Platform Modernization (DPM) Plan.

Experimental Company-Owned LED Light Program

The Experimental Company-Owned LED Lighting Program costs are recovered through the Tariff program, originally approved in Case No. 14-1027-EL-ATA on November 20, 2014, and

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[94] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[95] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[96] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[97] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-032.

continued by Commission Order in Case 16-470-EL-ATA on October 12, 2016.[98] The Companies stated that the Companies' Experimental Company Owned LED Program has its own FERC subaccount, Account 373.3 LED SL Ohio Tariff. The Companies provided a list of the work order numbers and the FERC accounts that are used to record Experimental Company Owned LED Lights.

As discussed further in the Work Order Backlog subsection, the Companies used a consolidated unitization process to reduce the backlog. When asked how the Companies identified plant associated with the Experimental Company-Owned LED Lighting Program in the consolidated unitization to ensure it was excluded from the DCR, the Companies stated that, upon further review, it found work order activity that should have been excluded.[99] The following work orders associated with the Experimental Company-Owned LED Lighting Program within the consolidated unitization should have been excluded from the DCR.[100]

Table 20: Experimental Company-Owned LED Lighting Program Work Orders Included in Consolidated Unitization that Should Have Been Excluded from the DCR

Company	WO #	Amount
CECO	15628465	$ (833)
OECO	15635688	$ (200)
TECO	15450219	$ 32,702
TECO	15483448	$ 24,938
TECO	15695871	$ 11
TECO	15711279	$ 1,766
TECO	15773451	$ 1,303
TECO	15786237	$ 609
TECO	15793170	$ 1,169
TECO	15906505	$ 308
TECO	PA92219130	$ 292
TECO	PA95716590	$ 1,310
Total		**$ 63,374**

The Companies stated (and Blue Ridge recommends) that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity been appropriately excluded.[101] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #3**].

The consolidated unitization was applied to work orders in the backlog that were mass property with an as-built and labor and material charge.[102] The Experimental Company-Owned LED Lighting Program costs that are recovered through the Tariff program include FERC accounts that may be considered mass property. The Companies stated that there are LED charges in FERC accounts 364, 365, 367, 368, and 373.1 and 373.3. Costs associated with these FERC accounts are also recoverable through the DCR. Therefore, we were unable to confirm whether any additional LED costs (beyond

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[98] FirstEnergy's response to 2017 Data Request BRC Set 11-INT-004.
[99] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-004.
[100] WP LED Exclusions BRC Set 2-INT-004 Attachment 2 Confidential.
[101] FirstEnergy's response to 2018 Data Request BRC Set 15-INT-001.
[102] FirstEnergy's response to 2018 Data Request BRC Set 8-INT-002.

those identified by the Companies) were included in the consolidated unitization work orders charged to the DCR. Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through Experimental Company-Owned LED Lighting Program is properly identified and excluded from the DCR.

Government Directive Recovery Rider (Rider GDR)

Government Directive Recovery Rider (Rider GDR) has the potential to impact the Rider DCR in the future. Rider GDR recovers costs associated with federal or state government mandates enacted after August 4, 2014. No activity has occurred on Rider GDR to date.[103] The Companies stated that to the extent the Rider GDR is populated in the future any costs included for recovery would exclude capital additions or other components that are currently being recovered through Rider DCR.[104] The GDR projects would have their own funding projects and work orders.[105]

Distribution Platform Modernization (DPM) Plan

The Companies filed a Distribution Platform Modernization (DPM) Plan in Case No. 17-2436-EL-UNC on December 4, 2017. Recovery of the costs associated with the DPM is pending resolution as part of a Stipulation and Recommendation filed on November 9, 2018, in Case Nos. 16-481-EL-UNC, 17-2436-EL-UNC, 18-1604-EL-UNC, and 18-1656-EL-ATA. The Companies' first phase of a grid modernization plan ("Grid Mod I") includes attributes from both the grid modernization business plan and the DPM Plan. There is no proposal to recover these costs through a separate Distribution Platform Modernization Rider. The Stipulation states that recovery of capital costs of the Grid Mod I assets will be through the Rider AMI.[106] This case is pending approval by the Commission. The Companies have not incurred any costs related to Grid Mod I.[107] Thus, there is no effect on this year's Rider DCR compliance audit.

In anticipation of the future recovery of the Grid Mod I work and how recovery will be excluded from the DCR, Blue Ridge requested that the Companies identify the DPM-type projects. In its response, the Companies referred to the stipulation.[108] The stipulation describes the type of investments that would be included in Grid Mod I[109] and the level of capital investments.[110]

The Grid Mod I projects are expected to use the same plant accounts (FERC 300) as projects recovered through the DCR. The Companies anticipate adding a new subaccount for capital costs associated with AMI investments, as those have a different depreciation rate.[111]

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[103] FirstEnergy's response to 2018 Data Request BRC Set 11-INT-033.
[104] WP FE response to 2016 audit Data Request BRC Set 10-INT-001 - Confidential.
[105] FirstEnergy's response to 2018 Data Request BRC Set 2-005.
[106] Case No. 16-481-EL-UNC, et. all, Stipulation dated November 9, 2018, pages 10–11.
[107] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-034.
[108] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-003 and Case No. 16-481-EL-UNC, et. al. Stipulation dated November 9, 2018 and Supplemental Stipulation dated January 25, 2019.
[109] Case No. 16-481-EL-UNC, et. all, Stipulation dated November 9, 2018, pages 14–21.
[110] Case No. 16-481-EL-UNC, et. all, Stipulation dated November 9, 2018, page 25.
[111] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-003, b.

The Companies were asked to provide the control/process mechanism that will be used to identify the difference between capital projects related to Grid Mod I versus those recovered through the DCR. The Companies issued this reply:

> Similar to the current process for exclusions related to Riders AMI and EDR(g), Grid Mod I will have its own funding project and work orders that will be tracked separately from the work in Rider DCR and clearly identifiable to be excluded from the Rider DCR calculations.
>
> Prior to each Rider DCR filing, the Companies review actual and forecasted work order detail, and will be able to locate and exclude activity related to Grid Mod I, based on the funding project and work orders assigned.[112]

Blue Ridge found that the Companies' planned process to identify and exclude Grid Mod I projects from the DCR to be not unreasonable.

Conclusion—Other Riders

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include projects related to Experimental Company Owned LED Light Program, Government Directive Recovery Rider (Rider GDR), and Distribution Platform Modernization (DPM) Plan. With the exception of the Companies-identified Experimental Company Owned LED Lights that should have been excluded, Blue Ridge found no project costs related to LED, GDR, or DMP in the work order sample.

<u>General Adjustments</u>

Consistent with Case No. 07-551-EL-AIR, the Companies removed land leased to ATSI, FirstEnergy's transmission subsidiary, from Rider DCR. The amounts are not jurisdictional to distribution-related plant in service and were excluded accordingly from each operating company.

Table 21: ATSI Land Lease (FERC Account 350) Excluded from Rider DCR[113]

Company	Actual 11/30/18		Estimated 2/28/19	
	Gross	Reserve	Gross	Reserve
CEI	$ 56,400,739	$ -	$ 56,400,739	$ -
OE	86,977,415	-	86,977,415	-
TE	15,628,438	-	15,628,438	-
Total	$ 159,006,592	$ -	$ 159,006,592	$ -

The ATSI Land Lease exclusion value was changed by the amount of incremental activity (net of additions, retirements, transfers, and adjustments) in FERC Account 350. Blue Ridge confirmed the incremental change from the prior year's balance.[114] The change is shown in the following table:

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[112] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-003, d.
[113] CEI, OE, and TE Rider DCR Compliance Filings dated 1.2.2019, page 19 and page 44.
[114] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-026.

Table 22: ATSI Land Lease Incremental Change 11/30/2017–11/30/2018

Description	CEI	OE	TE	Total
11/30/2017 Rider DCR Amounts	$ 56,405,971	$ 86,977,415	$ 15,628,438	$ 159,011,823
11/30/2018 Rider DCR Amounts	$ 56,400,739	$ 86,977,415	$ 15,628,438	$ 159,006,592
Change from 2017 to 2018 (Incremental Activity)	$ 5,231	$ -	$ -	$ 5,231

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include ATSI Land Lease amounts. No work related to ATSI Land Lease was identified within the sample.[115]

Generation

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include generation amounts. Blue Ridge found no generation amounts included within the sample work orders that should have been removed.

Conclusion—Rider LEX, EDR, AMI, and General Exclusions

The Companies' reporting of AMI amounts excluded, supported by multiple sources, lacks transparency. The Summary of Exclusions included in the DCR does not reflect all the AMI-recovered plant. Blue Ridge recommends that the Companies modify the reported Summary of Exclusions to reflect the AMI plant that is actually excluded.

The Companies use of a consolidated unitization process to reduce its backlog was applied to mass property work orders. When asked how the Companies ensured that plant associated with plant recovered through other riders in the consolidated unitization was identified and excluded from the DCR, the Companies stated that, on further review, it found an EDR and several Experimental Company-Owned LED Lighting Program work orders that should have been excluded from the DCR. Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the activity been appropriately excluded.

The FERC accounts included in the consolidated unitization includes FERC accounts that are recovered through the DCR as well as through other riders. Therefore, we were unable to confirm that the consolidated unitization work orders identified and properly excluded costs that are recovered through other riders.[116] Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through other riders is properly identified and excluded from the DCR.

GROSS PLANT IN SERVICE

E. Determine if the Companies' recovery of the incremental change in Gross Plant are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

[115] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1c.
[116] For further discussion of consolidated unitization, see the Work Order Backlog subsection of this report.

The Rider DCR Compliance Filings include the following gross plant-in-service incremental change for each company from the time of the prior audit.

Table 23: Incremental Change in Gross Plant from 11/30/17 to 11/30/18[117]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	3,072,113,869	3,177,791,509	105,677,640
Ohio Edison Company	3,473,934,081	3,581,667,230	107,733,149
The Toledo Edison Company	1,190,363,521	1,219,433,557	29,070,036
Total	7,736,411,471	7,978,892,296	242,480,826

Actual and Estimated Schedules B-2.1 support the incremental change in gross plant in service for transmission, distribution, and general plant. Other plant includes intangibles that are supported on separate schedules within the filings. The plant balances developed on these schedules are used throughout the Rider DCR revenue requirement calculations.

The Companies did not have any large construction and/or replacement programs in 2018. Each company had normal, recurring replacement programs, including Pole Replacements, Underground Cable Replacement, Feeder Repair/Replacement, Worst Performing Circuit/CEMI Program, and Downtown Network Upgrades.[118]

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included in the actual and estimated schedules that support gross plant and also verified that gross plant balances rolled forward to the revenue requirement calculation correctly. We did not identify anything in the mathematical computations as unreasonable.[119]

Source Data Validation

Blue Ridge traced the values used for actual November 30, 2018, and estimated February 28, 2019, gross plant-in-service balances to source documentation. The actual and estimated balances reconciled to the supporting documents. The supporting workpapers for the February 28, 2019, estimate recognize a true-up of forecast to actual November 30, 2018, balances and adjustments from prior audits.[120]

Change in Pension Accounting

Schedule B-2.1 includes a note that plant in service is adjusted to remove the cumulative pre-2007 impact of a change in pension accounting. In the prior audit, FirstEnergy explained the adjustment as follows:

> Effective in the fourth quarter of 2011, FirstEnergy Corp. (FE) elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and other postretirement plans (OPEB). Previously, FE recognized actuarial gains and losses as a component of Accumulated Other Comprehensive Income (AOCI) within

[117] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[118] FirstEnergy's response to Data Request BRC Set 1-INT-019 - Confidential.
[119] WP V&V FE DCR Compliance Filing 01.2.2019—Confidential.
[120] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-001, Attachments 3, 4, 5, 6, 7 and 8—Confidential.

> the Consolidated Balance Sheets on an annual basis. Actuarial gains and losses that were outside a specific corridor were subsequently amortized from AOCI into earnings over the remaining service life of affected employees within the related plans. Under the new methodology, which is preferable under GAAP, FE has elected to immediately recognize net actuarial gains and losses in earnings, subject to capital labor rates, in the fourth quarter of each reporting year as gains and losses occur and whenever a plan is determined to qualify for a re-measurement during a reporting year. The cumulative impact of this change in accounting methodology was reflected in FE's 2011 year-end financial results. Net plant in service was impacted by the appropriate capitalized portion of actuarial gains and losses recognized as a result of this accounting methodology change.[121]

Blue Ridge found FirstEnergy's explanation to be not unreasonable. In addition, Blue Ridge compared the Change in Pension Accounting amounts from year to year and found that the amounts were the same.[122]

<u>Additional Validation Testing from Sampled Work Orders</u>

The Companies provided a list of work orders that support gross plant in service for December 2017 through November 2018.[123] Blue Ridge validated that the work order amounts reconciled to the Companies' DCR filing gross plant balances.[124] Blue Ridge sorted the work order population by work order number and reviewed the population for work order numbers that represent plant that is specifically excluded from Rider DCR. Blue Ridge's findings are discussed in the Rider LEX, EDR, AMI, and General Exclusions section. In addition, the population was scanned for unusual transactions and included them as judgment samples if not selected in the statistical sample.

In addition to global evaluations of the population, Blue Ridge selected work orders for additional detail testing. Using probability-proportional-to-size (PPS) sampling techniques[125] and professional judgment, Blue Ridge selected 58 work orders representing 134 FERC cost line items for detailed transactional testing. The following table provides the number of work orders and FERC cost line items in the population and the number in Blue Ridge's sample.

[121] WP FE response to 2011 Audit Data Request BRC Set 14-INT-001.
[122] WP FEOH 2018 Pre-Date Certain Pension Impact Analysis 2012-2018 - CONFIDENTIAL.
[123] FirstEnergy's response to Data Request BRC Set 1-INT-002, Attachment 1—Confidential.
[124] WP 2018 BRC Set 1-INT-001 ATT 1 and 3 and 1-INT-006 Comparison, FirstEnergy's response to Data Request BRC Set 1-INT-002, Attachment 1 and Attachment 3—Confidential and FirstEnergy's response to Data Request BRC Set 1-INT-006.
[125] WP FEOH 2018 Sample Size Calculation Work Orders through 11-30-18 - CONFIDENTIAL.

Table 24: Work Orders and FERC Cost Line Items in Population and Sample by Company[126]

	Population			Sample			
	Work Orders	FERC Cost Line Items	Work Order Amounts	Work Orders	FERC Cost Line Items	Work Order Amounts	% Sample of Population
Cleveland Electric	24,612	35,454	$101,716,513	18	54	$29,714,597	29%
Ohio Edison	30,394	47,214	$101,978,985	18	37	$26,763,781	26%
Toledo Edison	12,089	17,493	$27,730,292	16	37	$5,466,076	20%
Service Company	144	154	$33,408,328	6	6	$12,775,318	38%
Total	**67,239**	**100,315**	**$264,834,117**	**58**	**134**	**$74,719,773**	**28%**

The testing of work orders included review of project justifications, project actual versus budgeted cost, variance explanations, reasonableness of the in-service dates in comparison to the estimated in-service dates, proper charge of the actual detailed cost to the proper FERC account, AFUDC charge on the work order (and if so, that it was appropriate), timeliness of recording of asset retirements for replacement work orders, and appropriate charge of cost of removal. The results of the detailed transaction testing performed on the work order sample are included in the workpapers.[127] Specific observations and findings about the testing are listed below.

Description of Projects

The Companies provided descriptions of the projects included in the work order sample. In general, the projects may be categorized according to the following types of additions and replacements.

1. Installation of underground and overhead conduit, conductors, and devices, including installation on customer premises
2. Meters
3. Station equipment
4. Street lighting
5. Structures and improvements
6. Office furniture and equipment
7. Line transformers
8. Poles, towers, and fixtures
9. Services
10. Miscellaneous intangible plant (software)
11. Communication equipment

Project Testing

The sampled work orders were evaluated based on objective criteria identified as T1 through T10.[128] Blue Ridge's observations and findings against the criteria are summarized below.

[126] FirstEnergy's response to Data Request BRC Set 1-INT-002 and WP FEOH 2018 Sample Size Calculation Work Orders through 11-30-18-Confidential.xlsx
[127] WP FEOH 2018 Sample Work Order Testing Matrix-Confidential.
[128] WP FEOH 2018 Sample Work Order Testing Matrix-Confidential.

T1: The work is appropriately includable in Rider DCR. Rider DCR includes plant in service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies.

Blue Ridge found that with the exception of vegetation management discussed below, plant in service was associated with distribution, subtransmission, and general and intangible plant.

Tree Trimming and Clearing and Grading of Land

Blue Ridge's sample included three work orders related to vegetation management (Tree Trimming):

- Work Order CE-900186-VMPL-DIST – Total Project - $8,449,761: 'OE-D-VEG Mgmt Program 2018 - 4986 Miles Planned OE-D-VEG Mgmt Program 2017 - 5143 Miles Planned OE-D-VEG Mgmt Program 2016 - 3953 Miles Planned OE-D-VEG Mgmt Program.[129]
- Work Order: OE-900186-VMPL-DIST – Total Project - $7,741,397: For 2018, this program covers a total of 2,074 circuit miles (1,849 distribution, 225 sub-transmission) of vegetation management and will encompass the planned removal of overhanging branches and off corridor trees, both of which may be capitalized. Includes ALL contractor dollars. [130]

As discussed in the Processes and Controls section of this report, Blue Ridge finds the Companies' policy Accounting for the Clearing of Transmission and Distribution Corridors at odds with the FERC Uniform System of Accounts. Based upon our further review of the Companies' vegetation management capitalization process, we found that the Companies use cost category codes to determine whether work should be charged to expenses or capital. We identified several codes used that we believe are inappropriate to be charged to capital:

- Cost Category 05—Off Corridor or removal of on corridor tree with overhang
- Cost Category 36—Cut Tree in the Clear Off Corridor No Future Maintenance Required.
- Cost Category 14—Overhead Limb Removal
- Cost Category 30—Property Owner Notification Capital

Because of our concerns regarding the proper coding of vegetation management costs and whether these costs should be recovered through the DCR as capital, Blue Ridge identified all the vegetation management work orders in the population.

[129] WP FEOH 2018 Sample Work Order Testing Matrix-Confidential and FirstEnergy's response to Data Request BRC Set 3-INT-001, attachment 1—Confidential.
[130] WP FEOH 2018 Sample Work Order Testing Matrix-Confidential and FirstEnergy's response to Data Request BRC Set 3-INT-001, attachment 1—Confidential.

Table 25: Vegetation Management Work Orders

Company	Work Order Number	FERC Account	Included in Sample	Not in Sample	Total
CECO	CE-900186-VMPL-DIST	365	$ 8,449,761		$ 8,449,761
CECO	CE-900187-VMPL-SUBT	356		$ 110,337	$ 110,337
CECO	CE-900187-VMPL-SUBT	365		$ (1)	$ (1)
CECO	CE-900189-VMUPL-DIST	365		$ (82,874)	$ (82,874)
CECO	CE-900190-VMUPL-SUBT	365		$ 99,828	$ 99,828
	CECO Total		**$ 8,449,761**	**$ 127,291**	**$ 8,577,052**
OECO	OC-900186-VMPL-DIST	365		$ 7,494	$ 7,494
OECO	OC-900188-VMPL-TRAN	356		$ 3,528	$ 3,528
OECO	OE-900186-VMPL-DIST	365	$ 7,741,397		$ 7,741,397
OECO	OE-900187-VMPL-SUBT	356		$ 50,657	$ 50,657
OECO	OE-900189-VMUPL-DIST	364		$ (174,879)	$ (174,879)
OECO	OE-900189-VMUPL-DIST	365		$ 348,435	$ 348,435
OECO	OE-900190-VMUPL-SUBT	356		$ 16,760	$ 16,760
	OECO Total		**$ 7,741,397**	**$ 251,995**	**$ 7,993,391**
TECO	TW-900186-VMPL-DIST	365	$ 2,013,282		$ 2,013,282
TECO	TW-900187-VMPL-SUBT	356		$ (4,116)	$ (4,116)
TECO	TW-900187-VMPL-SUBT	365		$ 11,542	$ 11,542
TECO	TW-900189-VMUPL-DIST	365		$ 26,238	$ 26,238
	TECO Total		**$ 2,013,282**	**$ 33,664**	**$ 2,046,946**
	Grand Total		**$ 18,204,439**	**$ 412,949**	**$ 18,617,389**

Blue Ridge obtained the charges to Cost Category Codes 05, 36, 14, and 30 for the all of the vegetation management work orders in the population[131] as shown in the following table:

Table 26: Vegetation Management Work Orders Charged to Cost Codes, 05, 14, 30, and 36

Company	Work Order	FERC Account	Code 05	Code 14	Code 30	Code 36	Total
CEI	CE-900186-VMPL-DIST	365	$ 80,906	$ 7,535,111	$ 286,751	$ 203,817	$ 8,106,585
CEI	CE-900187-VMPL-SUBT	356	82,625	350,640	14,072	4,004	451,341
CEI	CE-900189-VMUPL-DIST	365	180,660	107,978	353	37,185	326,176
CEI	CE-900190-VMUPL-SUBT	365	-	950	-	745	1,695
	Total CEI		**$ 344,191**	**$ 7,994,679**	**$ 301,176**	**$ 245,751**	**$ 8,885,797**
OE	OE-900186-VMPL-DIST	365	$ 331,365	$ 5,593,757	$ 498,679	$ 562,807	$ 6,986,608
OE	OE-900187-VMPL-SUBT	356	9,804	40,835	1,788	8,010	60,437
OE	OE-900189-VMUPL-DIST	365	22,765	7,971	68,150	75,023	173,909
OE	OE-900190-VMUPL-SUBT	356	9,770	711	1,002	5,211	16,694
	Total OE		**$ 373,704**	**$ 5,643,274**	**$ 569,619**	**$ 651,051**	**$ 7,237,648**
TE	TW-900186-VMPL-DIST	365	$ 43,577	$ 1,632,216	$ 163,482	$ 61,625	$ 1,900,900
TE	TW-900187-VMPL-SUBT	365	503	12,504	146	-	13,153
TE	TW-900189-VMUPL-DIST	365	3,346	4,243	12,349	5,790	25,728
	Total TE		**$ 47,426**	**$ 1,648,963**	**$ 175,977**	**$ 67,415**	**$ 1,939,781**
	Grand Total		**$ 765,321**	**$ 15,286,916**	**$ 1,046,772**	**$ 964,217**	**$ 18,063,226**

131 FirstEnergy's response to Data Request BRC Set 16-INT-001.

Blue Ridge recommends that capital costs charged to Cost Category Codes 05, 36, 14, and 30 be excluded from Rider DCR as they do not meet the FERC Uniform System of Accounts definition of capital expenditures.[132] Blue Ridge's recommendation removes $8,885,797 from CECO, $7,237,648 from OE, and $1,939,781 from TE.[133]

Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(1,786,623) for CECO, $(1,141,265) for OE, and $(364,336) for TE [**ADJUSTMENT #4**].

T1a: Exclusions Rider AMI: Review project descriptions for Distribution projects (FERC 360 accounts) to ensure that those descriptions exclude any discussion of any excluded[134] AMI or SmartGrid projects.

The sample contained four AMI/SmartGrid related work orders:

- CECO—990274 - SGMI CBS Phase-2 Closeout - $210,957 (charged to FERC 370)
- CECO—996102 - SGIG Project Mgmt - VVC Line - $35,618 (charged to FERC 391)
- CECO—996283 - DC Design - $120,397 (charged to FERC 391)
- CECO—CE-004000-SG-33 - SGMI Data Collection - $79,459 (charged to FERC 391)

The Companies stated, and Blue Ridge confirmed, that these costs were excluded from Rider DCR.

T1b: Exclusions Rider LEX: Review descriptions for Distribution projects only (FERC account 360 - Distribution Plant – Land and Land Rights) to ensure that they do not include line extension work.

Blue Ridge reviewed the project scope for each work order that had FERC account 360 charged to confirm that LEX work orders were properly excluded from Rider DCR. Blue Ridge found that the sample did not include any LEX work orders.[135]

T1c: Exclusions Rider EDR: Review project descriptions for CECO and FE to ensure that the projects do not include work for the Cleveland Clinic Foundation.

Blue Ridge did not find any work order descriptions in the sample that indicated the work was done in connection with the Cleveland Clinic Foundation and EDR(g).[136]

T1d: Exclusions GEN: Review project descriptions to ensure that the projects do not include generation work.

Blue Ridge found no work orders in the sample related to generation.[137]

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[132] For further discussion of vegetation management capitalization issue, see the Processes and Controls section.
[133] WP Vegetation Management Work Orders.
[134] FirstEnergy's response to Data Request BRC Set 2-INT-006 Attachment 1 - Confidential.
[135] FirstEnergy's response to Data Request BRC Set 1-INT-005, part d - Confidential.
[136]WP FEOH 2018 work order testing matrix.
[137]WP FEOH 2018 work order testing matrix and First Energy's response to Data Request BRC Set-1-INT-005, part a - Confidential.

T1e: Exclusions Rider GDR: Review project descriptions to determine that the projects do not include work from the Government Directive Recovery Rider (Rider GDR).

The Companies do not currently have any GDR projects.[138]

T1f. Exclusions Rider DPM: Review project descriptions to determine that the projects do not include work from the Distribution Platform Modernizations (DPM) plan.

The Companies do not currently have a DPM Rider.[139]

T2: Work order packages contain the project approval documentation or work order was approved at the project level.

Blue Ridge found that the Companies have adequate procedures in place to approve work orders. The procedures have not changed since our prior year review and, if followed, will yield the proper project approvals. Blue Ridge found no instance in which the Companies did not follow their stated policies.[140]

T3: For specific work orders (i.e., not a blanket work order or multi-year project, such as pole and meter replacements), the work order packages contain project justification.

Blue Ridge reviewed the justification for all work orders in the sample, exclusive of blanket, multi-year projects, transfers, and adjustments, and found all project work orders included justifications that were not unreasonable.

T4: Project costs are within the approved budget. Explanations and approval for cost overruns were provided.

In summary, Blue Ridge found the following calculated results:

39%—21 projects over budget greater than 15%
37%—20 projects were over/under budget by less than 15%
24%—13 projects did not have budgets (emergent work, accounting work orders, or storm work)

Four projects were determined to be AMI and excluded from the DCR. Additional testing was not required.

The Companies provided explanations for the 21 projects that were over budget by more than 15%:

1. OECO Work Order 13287497 –2012 SCADA Install Dx Feed
    a. Actual Capital Spend: $9,094,211.59
    b. Budget: $4,493,026.68
    c. Over budget by 102.4%: $4,601,184.91
    d. Description: Install SCADA Control and telemetering of watts, vars, amps, and volts on (6) distribution exit breakers and (2) transfer breakers. Install transformer

[138] First Energy’s response to Data Request BRC Set 2-INT-005, b.
[139] First Energy’s response to Data Request BRC Set 2-INT-003.
[140] FirstEnergy’s response to Data Request BRC Set 1-INT-012—Confidential, and BRC Set 1-INT-025.

telemetering where not already available. The scope also extends to include adaptive relaying where applicable. Now scheduled 1st quarter 2017

e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.

2. OECO Work Order 13335956 - OE- 2012 SCADA Installations
    a. Actual Capital Spend: $9,094,211.59
    b. Budget: $4,493,026.68
    c. Over budget by 102.4%: $4,601,184.91
    d. Description: Install SCADA Control and telemetering of watts, vars, amps, and volts on (6) distribution exit breakers and (2) transfer breakers. Install transformer telemetering where not already available. The scope also extends to include adaptive relaying where applicable. Now scheduled 1st quarter 2017
    e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
3. OECO Work Order 14370674 - SUB REMOVE SWITCHGEAR
    a. Actual Capital Spend: $597,388.53
    b. Budget: $173,964.01
    c. Over budget by 243.4%: $423,424.52
    d. Description: Remove existing unit sub switchgear and replace existing ABB reclosers with R-Mag Reclosers. Install breaker disconnect switches and associated required structures.
    e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
4. OECO Work Order 14565045 - Substation, Tap of Sammis-P
    a. Actual Capital Spend: $4,549,650.19
    b. Budget: $2,496,611.17
    c. Over budget by 82.2%: $2,053,039.02
    d. Description: Build a new 138 kV to 12.47kV distribution mod substation in Columbiana county, west of Lisbon. Tap the Sammis-Pidgeon 138kV line near tower 8405 and add a radial tap to the new sub property. Location may be under the 345/138kV corridor. Add 2 network SCADA line switches, and a wavetrap at the mod sub. Sub location still being determined by Real Estate and OE.
    e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
5. OECO Work Order 14777263 - SUB I/R BREAKERS
    a. Actual Capital Spend: $603,135.88
    b. Budget: $174,137.44
    c. Over budget by 246.4%: $428,998.44

   d. Description: Revised scope 3/17/2016: Replace B-97 (transfer breaker) in-place of B-95 due to current condition of the breaker. B-53 still being replaced under this project. Replace existing 23 kV breakers B-95 Farrell and B-53 No. 3 Xfmr breaker due to condition. Replace with FE standard 25 or 34.5 kV breakers or similar to existing rating.
   e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
6. OECO Work Order 15519854 - COL-17-17.50 PID 99955
   a. Actual Capital Spend: $2,126,504.61
   b. Budget: $932,735.05
   c. Over budget by 128%: $1,193,769.56
   d. Description: OE - Forced - N-Highway Relocation-OH Facility
   e. Reason for cost overrun: Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget for the year.
7. OECO Work Order 15750830 - Urban/ Q2 CBL FLT: 4/27/2018
   a. Actual Capital Spend: $605,465.02
   b. Budget: $140.04
   c. Over budget by 432251%: $605,324.98
   d. Description: SAP order # 15750830 is a Cable Fault that occurred in Akron. The crews replaced the underground cable.[141]
   e. Reason for cost overrun: Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget for the year.
8. OECO Work Order PA101696420 - PO FW: UG Transformer 73BC1D-9 C MARKET
   a. Actual Capital Spend: $18,426,311.46
   b. Budget: $9,121,724.82
   c. Over budget by 102%: $9,304,586.64
   d. Description: OE - Blanket - Forced Failures
   e. Reason for cost overrun: Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget for the year.

For numbers 6, 7, and 8 above, the Companies explained that the blanket spending was actually 25% below budget in the aggregate. In addition, they further explained, "Although blankets in total were in line with prior years and were in line with approved spending levels, the misallocations between blanket work types in the budget caused significant offsetting variances between categories. The incorrect allocation was an error that has since been

[141] First Energy's response to 2018 Data Request BRC Set 13-INT-006.

addressed to ensure the same issue does not occur in future budgets."[142] Blue Ridge finds the explanation not unreasonable.

9. OECO Work Order PA99685200 - PO FW: 59BN4C-531 [MDT Comments SPERLI
    a. Actual Capital Spend: $18,426,311.46
    b. Budget: $9,121,724.82
    c. Over budget by 102%: $9,304,586.64
    d. Description: OE - Blanket - Forced Failures
    e. Reason for cost overrun: Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget. Ohio Edison has a portfolio of blanket work on an annual basis made up mainly of work associated with Capacity, Condition, Forced, Meter Related, New Business, Street Lighting, and Tools & Equipment. The total 2018 blanket portfolio was in line with prior years' spending and consistent with approved spending levels, though the allocations among the blanket categories were not consistent with historical spending levels. For the 2018 budget, the Condition work was allocated a higher amount of the total blanket portfolio than historically spent, while other categories (Capacity, Forced, and Tools & Equipment) were allocated less than historical amounts spent. The Companies indicated that they have addressed the procedural problem causing the inappropriate allocations to ensure a similar issue does not occur in future budgets. This misallocation among blanket categories in the 2018 budget did not have any impact on the Rider DCR revenue requirement[143] for the year. Blue Ridge finds the Companies' explanation not unreasonable.
10. OECO Work Order IF-OE-000127 - OE - Fairlawn Rpl B001 R02
    a. Actual Capital Spend: $352,813.44
    b. Budget: $149,084.73
    c. Over budget by 136.7%: $203,728.71
    d. Description: Replace Roof 2 at Fairlawn Building 2
    e. Reason for cost overrun: The variance is largely due to the fact that Overheads and AFUDC were not included the original budget.
11. CECO Work Order 14857540 - Sub - Replace Voltage Regulatio
    a. Actual Capital Spend: $1,160,871.77
    b. Budget: $555,024.57
    c. Over budget by 109.2%: $605,847.20
    d. Description: Replace PLC Voltage Regulation scheme with new Reinhausen TapCon control scheme
    e. Reason for cost overrun: Labor and Pension and OPEB Non-Service costs higher than planned.
12. CECO Work Order PA103998630 - PO FW: Fuse Installation 504582B 25T UD
    a. Actual Capital Spend: $5,244,083.03
    b. Budget: $4,470,156.49
    c. Over budget by 17.3%: $773,926.54

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[142] FirstEnergy's response to 2018 Data Request BRC Set 11-INT-002 and attachment 1.
[143] First Energy's response to 2018 Data Request BRC Set 13-INT-007.

   d. Description: Replace failed URD cables at time of 3rd failure
   e. Reason for cost overrun: Professional & Contractor and Construction Overheads & Transportation cost higher than planned.
13. CECO Work Order IF-CE-000081 - CE - NRHQ Rpl Diesel Generator
   a. Actual Capital Spend: $455,882.08
   b. Budget: $351,025.42
   c. Over budget by 29.9%: $104,856.66
   d. Description: Replace Brecksville DCC NRHQ backup generators
   e. Reason for cost overrun: The variance is largely due to the fact that Overheads and AFUDC were not included the original budget.
14. TECO Work Order 15317256 - TES - RP 138kV ckt switcher
   a. Actual Capital Spend: $1,022,328.95
   b. Budget: $472,353.23
   c. Over budget by 116.4%: $549,975.72
   d. Description: Replace Decant 13280 Circuit Switcher with like-for-like at TE - 2017. Replace 13347 Circuit Switcher with like-for-like at TE - 2017.Purchase a spare 138kV Circuit Switcher
   e. Reason for cost overrun: Greater than planned Labor, professional contractor and overhead expenses were the main drivers in the unfavorable variance.
15. TECO Work Order 15466262 - Residential Development
16. TECO Work Order 15674084- Residential Development
   Work Orders 15466262 and 15674084 were included in the same project.
   a. Actual Capital Spend: $1,934,568.55
   b. Budget: $2,584.38
   c. Over budget by 74756%: $1,931,984.17
   d. Description: TE-Blanket-New Business Residential Underground
   e. Reason for cost overrun: The variance is due to Expenses being budgeted under a different Project WBS than the actuals were charged to. TW-900625: B-New Business- Residential Underground project was budgeted for $2.4M for same timeframe with no actuals charged to it.
17. TECO Work Order 15724705 - PowerOn Follow-up
   a. Actual Capital Spend: $197,662.10
   b. Budget: $13,790.40
   c. Over budget by 1333.33%: $183,871.70
   d. Description: TE-Blanket-Streetlight-Unscheduled Repair
   e. Reason for cost overrun: Main drivers for this variance were unplanned labor and construction overheads.
18. TECO Work Order 15840920 - Commercial
   a. Actual Capital Spend: $210,356.79
   b. Budget: $452.06
   c. Over budget by 46432%: $209,904.73
   d. Description: TE-Blanket-New Business-Commercial Overhead
   e. Reason for cost overrun: This project was placed on a different Blanket WBS than where the $ were budgeted within the New Business Commercial Overhead category. TW-900713: B-New Service-Commercial OH project had $735k budgeted with only a small amount of Actual expenses charged.

19. FECO Work Order ITS-SC-000507-1
    a. Actual Capital Spend: $191,314
    b. Budget: #146,841
    c. Over budget by 31.3%
    d. Description: NNMI System upgrade Cap.
    e. Reason for cost overrun: Implementation of SNMP v3 required more IT labor and client testing than projected. Also driving the variance were overheads which are not calculated for specific projects in the budgeting process.
20. CECO Work Order CE-700577
    a. Actual Capital Spend: $30,142
    b. Budget: $21,688
    c. Over Budget: 41.5%
    d. Description: IT upgrade. Remittance processing system.
    e. Reason for Cost overrun: Additional labor was required due to the need for a custom interface that was planned to be covered via standard data conversion processes.
21. TECO Work Order TW-700386
    a. Actual Capital spend; $345,050
    b. Budget: $160,179
    c. Over Budget: 115.4%
    d. Description: IT GIS Autodesk upgrade
    e. Reason for Cost overrun: There were application issues that required more vendor support, IT labor and business client testing than had been projected in the budget.

For most of the projects, the Companies' reasoning for each project's actual costs exceeding the budget was specific and unique to that project and not unreasonable.

However, approximately 39% of the projects that had budgets were over budget by greater than 15%. The large percentage of projects over budget raises a question about the Companies' planning process. Blue Ridge had similar concerns in the 2016 and 2017 audits. In recommendation #6 of its 2016 report, Blue Ridge recommended the Companies review the planning process. In recommendation #1 in the 2017 audit, Blue Ridge suggested internal audit review the planning process with an objective to confirm that project management methodology and process design allows for projects to be fully scoped prior to project execution. The report issued on April 17, 2017, included several recommendations that were expected to be complete by June 2018. [144] The Companies have implemented the recommendations from the Audit of the Distribution Portfolio and Planning Process.[145]

There were application issues that required more vendor support, IT labor, and business client testing than had been projected in the budget.

Blue Ridge understands that the Companies did not fully implement the audit recommendations until mid 2018, which is about halfway through the DCR audit scope period. Therefore, it is very possible most of the projects included in the DCR were planned and budgeted prior to the implementation of the audit recommendations. Blue Ridge recommends

[144] FirstEnergy's responses to 2017 Data Request BRC Set 4-INT-002, Attachment 1, a—Confidential and 2017 Data Request BRC Set 1-INT-011, Attachment 1 Confidential.
[145] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-010.

that this issue be revisited in the next DCR audit to determine whether the recommendations were fully implemented and, if so, their success in reducing the percentage of projects coming in over budget.

Projects Without Budgets

Blue Ridge found 13 projects that did not have budgets. The following three work orders were considered emergent projects and were not in the original capital budget.[146]

Table 27: List of Work Orders that were Emergent Projects and Not in Capital Budget

Company	Work Order	Work Order Description		Actual	Explanation
TECO	15803633	INSTALL POLES AND BORE NEW CABLE	$	219,444	Intall Poles and bore new cable. These are considered Fix it now projects
OECO	OE-002086-F	12C Kinsman Paving	$	424,707	The Company replaced 4,000 sq. ft of asphalt in lay down area for safety of workers and mobile
TECO	15589873	Residential Development	$	85,725	This was a new residential underground project. Funds were budgeted to a different work order

In addition to the three emergent projects that did not have budgets, the remaining 10 work orders/projects selected for testing included five consolidated unitization work orders, three storm work orders, one accounting adjustment, and one work order that came about as a result of underspending on other projects.

T5: Cost detail in Power Plant supports the work order charge and the categories of cost are reasonable.

Two work orders had AFUDC that represented 35% of the total charges. Further investigation found that the in-service dates were entered incorrectly in PowerPlant and that AFUDC was over accrued. The date was corrected in February 2019 and adjustments were recorded to AFUDC.[147] Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the in-service dates for the work orders been entered correctly and AFUDC and not been over accrued.

- Work order OECO, 13335956: OE- 2012 SCADA Installations. The Companies estimate that AFUDC was overstated by $94,883[148] [**ADJUSTMENT #5**].
- Work order OECO, 13287497: 2012 SCADA install DX feed. Total AFUDC charged was $361,491 The Companies estimate that AFUDC was overstated by $142,684.[149]

  Blue Ridge has estimated the impact to the DCR revenue requirement calculations of the two work orders with incorrect in-service dates to be $(37,042) for OE [**ADJUSTMENT #6**].

[146] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 1.
[147] First Energy's response to 2018 Data Request BRC Set 7-INT-7-001, a and b.
[148] First Energy's response to 2018 Data Request BRC Set 13-INT-001.
[149] First Energy's response to 2018 Data Request BRC Set 13-INT-002.

Five work orders included in the work order sample were entitled *consolidated unitizations*, totaling $31,336,375. Those work orders were part of a mass unitization process. Further discussion of these work orders is included in the Work Order Backlog subsection of this report.

For the remaining work orders in the sample, Blue Ridge determined that the costs in PowerPlant support the work order charge and the categories of cost are not unreasonable.[150]

T6: Project detail indicates that assets were retired, and costs incurred for cost of removal and salvage.

Except for the 11 work orders discussed in testing step T6a and three in testing step T6b below, Blue Ridge found that, for replacement work orders, assets were retired, and cost of removal was charged. Scrap sales are not recorded on an individual work order. Scrap from multiple operating companies is charged to a separate work order, and the proceeds are allocated to the various operating companies based on their estimated contribution to the total scrap sale. When equipment is sold for other than scrap, the proceeds are charged to the accumulated reserve for depreciation.[151]

The process for recording scrap and equipment sales is common in the utility industry, and the end result conforms to FERC accounting requirements. Additional comments related to retirements and costs of removal are included in T6a and T6b below.

T6a: Replacement work orders: The date assets were retired, cost of removal date, and replacement asset in-service dates are in line.

The following work orders had cost of removal but no retirements charged.

Cost of Removal but no Retirements Charged

1. CECO Work Order 15821042-CE Consolidated Unitization 2016 - $2,616,182. Cost of removal was charged but not retirements.
2. CECO Work Order 15821043-CE Consolidated Unitization 2017 - $10,129,886. Cost of removal was charged but not retirements.
3. CECO Work Order 15821044-CE Consolidated Unitization 2018 - $5,686,341. Cost of removal was charged but not retirements.
4. OECO Work Order 15821683-OE Consolidated Unitization 2017 - $11,358,127. Cost of removal was charged but not retirements.
5. TECO Work Order 15821701-TE Consolidated Unitization 2017 - $1,575,839. Cost of removal was charged but not retirements.

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[150] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachments 3 and 4 - Confidential. WP BRCS Set 3-INT-001 Attachment 3, 4, and 5 Analysis. Cost detail in BRC Set 3-INT-001, Attachment 3 less the retirements in BRC Set 3-INT-001, Attachment 4 = the work order selection for replacement work orders—Confidential.

[151] WP FE response to 2015 audit Data Request BRC Set 13-INT-004 and response to Data Request BRC Set 1-INT-014.a.v - Confidential.

The Companies explained that for the three Consolidated Unitization work orders (2, 3, and 5 above), the retirements occurred on the original work orders, but the cost of removal charges booked to the original work order were transferred to the consolidated unitization work orders.[152] If the cost of removal had remained with the original work orders, each individual work order would have been required to be closed out manually and not through the mass property consolidated process.[153] The Companies' explanation is not unreasonable.

6. CECO Work Order 14857540- sub. Replace voltage regulator - $1,125,623.
7. CECO Work Order CE-001312-DO-MSTM-Total Distribution Line – STORM - $352,692. Cost of removal was charged but not retirements.
8. OECO Work Order 14370674- SUB REMOVE SWITCHGEAR - $541,052. Cost of removal was charged but not retirements.
9. OECO Work Order IF-OE-000127-1-OE - Fairlawn Rpl B001 R02 - $352,813. Cost of removal was charged but not retirements.

   For numbers 6, 7, 8, and 9 above, the Companies explained the work orders are completed, but not unitized. This work orders will be manually unitized (since not fed by a work management system) and the retirement will be done at the time of unitization.[154] The Companies explained that until the work orders are manually unitized, they cannot estimate the amount of the over accrual of depreciation. They do not expect the impact to be significant.[155] The work orders have been in service since January 29, 2017. While the unknown retirement will not affect net plant, it would affect depreciation expense in the DCR. Blue Ridge recommends that once the retirement is recorded, the Companies calculate the impact on depreciation and on the DCR.

10. OECO Work Order 14777263- SUB I/R BREAKERS - $439,207. Cost of removal was charged but not retirements. The Companies explained the retirement occurred when the work order was manually unitized, which was after 11/30/18 and therefore not included in the BRC Set 3 data.[156] The Companies indicate that OECO 14777263—sub I/R breakers was unitized January 14, 2019 and had $65,391.81 in retirements. Over accrual of depreciation for this work order from the date the retirement occurred to November 30, 2018, equals $784. The plant in service and accumulated reserve balances are both overstated by $65,392 as of November 30, 2018. These net to zero in net plant in service.[157] While the unknown retirement will not affect net plant, it would affect depreciation expense in the DCR. While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #7a**] Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR

[152] First Energy's response to 2018 Data Request BRC Set 7-INT-002.
[153] First Energy's response to 2018 Data Request BRC Set 13-INT-004.
[154] First Energy's response to 2018 Data Request BRC Set 7-INT-002.
[155] First Energy's reponsse to 2018 Data Request BRC Set 13-INT-003.
[156] First Energy's response to 2018 Data Request BRC Set 7-INT-002.
[157] First Energy's response to 2018 Data Request BRC Set 13-INT-005.

revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the retirement been recorded at the appropriate time.

11. OECO Work Order OE-002814-DO-MSTM-OE MSTM 9 5/22/18 T-STORM EVENT - $210,739. Cost of removal was charged but not retirements. The Companies explained that the retirement occurred when the work order was manually unitized, which was after 11/30/18 and therefore not included in the BRC Set 3 data.[158] The Companies indicate that this work order was unitized on 1/11/19 with $8,750.26 in retirements. Over accrual of depreciation for the work order from the date the retirement occurred to 11/30/2018 equals $155. The plant in service and accumulated reserve balances are both overstated by $8,750.26 as of 11/30/2018. These net to zero in net plant in service.[159] While the unknown retirement will not affect net plant, it would affect depreciation expense in the DCR. While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #7b**] Blue Ridge recommends that the Companies include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on the Rider DCR revenue requirement had the retirement been recorded at the appropriate time.

T6b: Replacement work orders: Cost of removal has been appropriately charged.

1. CECO Work Order IF-CE-000081-1-CE - NRHQ Rpl Diesel Generator - $455,882. Retirements charged but no cost of removal. The Companies' response indicates that there is no cost of removal charged for the replacement of the diesel generator. When the original estimate was created for the work, no removal was included. The order will be updated to add a cost of removal estimate and to transfer charges to removal.[160] Blue Ridge has estimated that updating the work order to charge cost of removal will have an immaterial impact on the DCR.
2. TECO Work Order 15209359 - Equip Investigate / Repair - Transforme - $(111,897). Retirements charged but no cost of removal. The Companies explained that the primary driver of the $(106,952) credit in other company overheads was the 2017 year-end pension mark-to-market adjustments recorded in December 17 and January 18. The explanation is not unreasonable.[161]
3. TECO work order, 15317256 TES RP 138KV ckt switcher that appeared to be a replacement project, did not have Cost of Removal charged. The Companies explained that the work order was auto-unitized based on the original work order estimate that did not have cost of removal included. It has since been manually unitized, which will trigger cost of removal and a retirement to be recorded. The Companies will include a reconciliation in the Rider DCR revenue requirement in a subsequent filing that incorporates the effect on revenues

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[158] First Energy's response to 2018 Data Request BRC Set 7-INT-002.
[159] First Energy's response to 2018 Data Request BRC Set 13-INT-005.
[160] First Energy's response to Data Request BRC Set 7-INT-003.
[161] First Energy's response to Data Requested BRC Set 7-INT-001.

as a result of this adjustment.[162] Blue Ridge has estimated that updating the work order to charge cost of removal will have an immaterial impact on the DCR.

T7: Following completion of the work, the work order was closed out to the proper FERC 300 account(s).

Except for the five work orders listed below Blue Ridge found that, based on the description of the work performed, all work orders in the sample were closed to the proper FERC accounts.[163]

- CECO Work Order 15821042 – CE Consolidation Unitization 2016 - $2,616,282.
- CECO Work Order 15821043 – CE Consolidation Unitization 2017 - $10,129,886
- CECO work Order 15821044 – CE Consolidation Unitizations 2018 - $5,686,341
- OECO work Order 15821683 – OE Consolidation Unitizations 2017 - $11,358,127
- TECO work Order 15821701 – TE Consolidation Unitizations 2017 - $1,575,839

Blue Ridge found that because of the volume of work orders included in the consolidated unitization and lack of detail, we were unable to confirm that the Companies' unitization resulted in the work orders being unitized to the proper FERC accounts. However, Blue Ridge believes that the potential misclassification to the wrong FERC 300 account would not be a significant concern. The consolidated unitization is discussed in the Work Order Backlog subsection.

T8: Actual in-service date is in line with the estimate (at or before).

Blue Ridge found that 33 work orders in our sample, were blankets or other types of work orders, such as emergent projects, storms, and adjustments, that would not typically have estimated in-service dates.

Of the 21 with estimated in-service dates, six, or approximately 29%, had in-service dates that were over 90 days delayed from the estimates.[164]

1. OECO Work Order 14370674 - SUB REMOVE SWITCHGEAR
    a. Capital Project Cost: $541,052
    b. In-Service Date: 5/2/18
    c. Need Date: 9/1/15
    d. In-Service days after estimated date: 974
    e. Description: Remove existing unit sub switchgear and replace existing ABB reclosers with R-Mag Reclosers. Install breaker disconnect switches and associated required structures.
    f. Reason for greater than 90-day delay: Project was deferred due to reallocation of labor resources. Not allowed to contract the work.
2. OECO Work Order 14565045 - Substation, Tap of Sammis-P

[162] First Energy's response to Data Request BRC Set 11-INT-004.
[163] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 1 and 3—Confidential.
[164] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 1 and Attachment 2. Note: one work order did not have an in-service date (item six below) but the Company gave a reason for the greater than 90 day delay.

   a. Capital Project Cost: $3,266,214
   b. In-Service Date: 5/8/18
   c. Need Date: 12/1/16
   d. In-Service days after estimated date: 523
   e. Description: Build a new 138 kV to 12.47kV distribution mod substation in Columbiana county, west of Lisbon. Tap the Sammis-Pidgeon 138kV line near tower 8405 and add a radial tap to the new sub property. Location may be under the 345/138kV corridor. Add 2 network SCADA line switches, and a wavetrap at the mod sub. Sub location still being determined by Real Estate and OE.
   f. Reason for greater than 90-day delay: Project was deferred due to reallocation of labor resources. Not allowed to contract the work.
3. OECO Work Order 14777263 - SUB I/R BREAKERS
   a. Capital Project Cost: $439,207
   b. In-Service Date: 5/14/18
   c. Need Date: 12/30/16
   d. In-Service days after estimated date: 500
   e. Description: Revised scope 3/17/2016: Replace B-97 (transfer breaker) in-place of B-95 due to current condition of the breaker. B-53 still being replaced under this project. Replace existing 23 kV breakers B-95 Farrell and B-53 No. 3 Xfmr breaker due to condition. Replace with FE standard 25 or 34.5 kV breakers or similar to existing rating.
   f. Reason for greater than 90-day delay: Project was deferred due to reallocation of labor resources. Not allowed to contract the work.

   For projects 1, 2, and 3 above, the Companies explained that the estimates were not updated because they had already received budgetary approval. The financial requirements of the scope were updated in the financial forecast. Original justifications are not required to be updated when there is a scope deferral or scope change.[165] In addition, additional costs were related to the need to add equipment at three locations.[166] Blue Ridge finds the reason the project estimates were not updated to be not unreasonable. However, it is unclear that the need for additional equipment and subsequent increase in cost was not either in whole or in part because of the significant project delay. Blue Ridge does not recommend an adjustment but does recommend that the Companies pay close attention to delays that may cause an increase in cost when the determination is made of how to allocate resources.

4. OECO Work Order IF-OE-000126 - OE - Fairlawn Rpl B001 R01
   a. Capital Project Cost: $345,450
   b. In-Service Date: 5/1/18
   c. Need Date: 12/31/17
   d. In-Service days after estimated date: 121
   e. Description: Replace Roof 1 at Fairlawn Building 1

[165] First Energy's response to 2018 Data Request BRC Set 11-INT-001, a.
[166] First Energy's response to 2018 Data Request BRC Set 11-INT-001, b.

   f. Reason for greater than 90-day delay: Project completed on schedule, reason for delay is work order not being closed in timely manner.
   g. The delay resulted in over accrued AFUDC ($17,956) and an overstatement of the depreciation expense. The Companies stated (and Blue Ridge recommends) that an adjustment be made to change the in-service date and to include a reconciliation in the Rider DCR revenue requirement in a subsequent filing.[167] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #8a**].
5. OECO Work Order IF-OE-000127 - OE - Fairlawn Rpl B001 R02
   a. Capital Project Cost: $352,813
   b. In-Service Date: 5/1/18
   c. Need Date: 12/31/17
   d. In-Service days after estimated date: 121
   e. Description: Replace Roof 1 at Fairlawn Building 2
   f. Reason for greater than 90-day delay: Project completed on schedule, reason for delay is work order not being closed in timely manner.
   g. The delay resulted in over accrued AFUDC ($11,497) and an overstatement of the depreciation expense. The Companies stated (and Blue Ridge recommends) that an adjustment be made to change the in-service date and to include a reconciliation in the Rider DCR revenue requirement in a subsequent filing.[168] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #8b**].
6. TECO Work Order TW-001489-F-3 - Lindsey
   a. Capital Project Cost: $320,531
   b. In-Service Date: 7/24/18
   c. Need Date: None Provided
   d. In-Service days after estimated date:
   e. Description: None provided
   f. Reason for greater than 90 day delay: Delayed completion of project due to securing funding from other sources and approval.[169] The Companies explanation is not unreasonable.

T9: The work orders were placed in service and closed to EPIS within a reasonable timeframe from project completion. If not, AFUDC was stopped.

As identified in testing step T8, Blue Ridge found two work orders were not closed timely after the work was complete and recommended adjustments.

1. OECO Work order IF-OE-000126-1 – Fairlawn Rpl. B001-R01 -$345,450. The work order was complete 12/31/17 but not placed in service until 5/1/18. A delay of 122 days.
2. OECO Work order IF-OE-000127-1 – Fairlawn Rpl B001-02 - $352,813. The work was complete 12/31/17 but not placed in service until 5/1/18. The delay was 122 days.

[167] First Energy's response to 2018 Data Request BRC Set 11-INT-003.
[168] First Energy's response to 2018 Data Request BRC Set 11-INT-003.
[169] FirstEnergy's response to Data Request BRC Set 3-INT-001 CONFIDENTIAL

T10: For work performed in 2018, this project is a candidate for field verification to determine whether it is used and useful.

Blue Ridge identified ten work orders within the sample as candidates for field visits. The field inspections are discussed in the next subsection.

Field Inspections

Blue Ridge selected ten projects for field verification from the work order sample. The purpose of the field verification was to determine whether the assets have been installed per the work order scope and description and whether they are used and useful in rendering service to the customer. The work order/project selection criteria were assets that can be physically seen and were installed within the scope period of this review. Experienced staff from the Public Utilities Commission of Ohio, with assistance from FirstEnergy representatives, conducted the field verifications in March. Staff was provided with information for each work order / project and completed a standard questionnaire developed by Blue Ridge for each location. Where possible, Staff took pictures of the installed assets. The completed questionnaires and pictures are included as workpapers with this report.

The following projects were field inspected:

1. CECO Work Order 14857540 - Sub Replace voltage regulator
    a. Description: Replace PLC Voltage Regulation scheme with new Reinhausen TapCon control scheme
    b. In-Service Date: 1/29/17
    c. Capital Project Costs: None
    d. Final Project Cost: $1,125,623
2. CECO Work Order IF-CE-000081-1 - CE - NRHQ Rpl Diesel Generator
    a. Description: Replace Brecksville DCC NRHQ backup generators
    b. In-Service Date: 1/24/18
    c. Capital Project Costs (excluding Overheads): $370,441
    d. Final Project Cost: $455,882
3. OECO Work Order 13287497 - 2012 SCADA Install Dx Feed
    a. Description: Install SCADA Control and telemetering of watts, vars, amps, and volts on (6) distribution exit breakers and (2) transfer breakers. Install transformer telemetering where not already available. The scope also extends to include adaptive relaying where applicable. Now scheduled 1st quarter 2017
    b. In-Service Date: 5/14/18
    c. Capital Project Costs (excluding Overheads): $109,647
    d. Final Project Cost: $1,039,577
4. OECO Work Order 14370674 - SUB REMOVE SWITCHGEAR
    a. Description: Remove existing unit sub switchgear and replace existing ABB reclosers with R-Mag Reclosers. Install breaker disconnect switches and associated required structures.
    b. In-Service Date: 5/2/18
    c. Capital Project Costs (excluding Overheads): None
    d. Final Project Cost: $541,052
5. OECO Work Order 14565045 - Substation, Tap of Sammis-P

   a. Description: Build a new 138 kV to 12.47kV distribution mod substation in Columbiana county, west of Lisbon. Tap the Sammis-Pidgeon 138kV line near tower 8405 and add a radial tap to the new sub property. Location may be under the 345/138kV corridor. Add 2 network SCADA line switches, and a wavetrap at the mod sub. Sub location still being determined by Real Estate and OE.
   b. In-Service Date: 5/8/18
   c. Capital Project Costs (excluding Overheads): None
   d. Final Project Cost: $3,266,214
6. OECO Work Order 14777263 - SUB I/R BREAKERS
   a. Description: Revised scope 3/17/2016: Replace B-97 (transfer breaker) in-place of B-95 due to current condition of the breaker. B-53 still being replaced under this project. Replace existing 23 kV breakers B-95 Farrell and B-53 No. 3 Xfmr breaker due to condition. Replace with FE standard 25 or 34.5 kV breakers or similar to existing rating.
   b. In-Service Date: 5/14/18
   c. Capital Project Costs (excluding Overheads): None
   d. Final Project Cost: $439,207
7. OECO Work Order IF-OE-000126-1 OE - Fairlawn Rpl B001 R01
   a. Description: Replace Roof 1 at Fairlawn Building 1
   b. In-Service Date: 5/1/18
   c. Capital Project Costs (excluding Overheads): $332,101
   d. Final Project Cost: $345,450
8. OECO Work Order IF-OE-000126-2 OE - Fairlawn Rpl B001 R02
   a. Description: Replace Roof 1 at Fairlawn Building 2
   b. In-Service Date: 5/1/18
   c. Capital Project Costs (excluding Overheads): $215,546
   d. Final Project Cost: $352,813
9. OECO Work Order OE-002086-F - 12C Kinsman Paving
   a. Description: concrete replacement 4,000sf laydown area, asphalt tearout replacement various
   b. In-Service Date: 11/5/15
   c. Capital Project Costs (excluding Overheads): None
   d. Final Project Cost: $424,707
10. TECO Work Order 15317256 - TES - RP 138kV ckt switcher
   a. Description: Replace Decant 13280 Circuit Switcher with like-for-like at TE - 2017. Replace 13347 Circuit Switcher with like-for-like at TE - 2017.Purchase a spare 138kV Circuit Switcher
   b. In-Service Date: 11/7/18
   c. Capital Project Costs (excluding Overheads): $248,000
   d. Final Project Cost: $494,040

The ten projects selected for field verification confirmed that the assets were installed and used and useful.

Work Order Backlog

Blue Ridge found that the Companies have made significant progress to reduce the unitization backlog for work orders over 15 months. Total work orders in the greater-than-15-month backlog were reduced by 53 percent from the end of 2017 to the end of 2018. Total dollars in the greater-than-15-month backlog were reduced by 64 percent.

Table 28: Backlog over 15 Months of Work Order Unitization[170]

Description	Unitization Backlog	Unitization Backlog $
as of 12/31/13	1,346	
as of 11/30/14	4,156	
as of 11/30/15	983	$3,959,518
as of 12/31/16	4,032	$62,191,009
as of 12/31/17	3,039	$39,928,597
as of 12/31/18	1,403	$14,122,115

FirstEnergy explained that the backlog was reduced using a two-step process. First, mass property work orders with as-builts and labor and material charges were grouped and unitized en masse.[171] Second, the remaining work orders were assigned to two full-time staff and one contractor who focused on the unitization in the fourth quarter of 2018.[172]

Blue Ridge found that the Companies unitized thousands of projects into work orders grouped by year, totaling $43,911,200. The process was identified by consolidated unitization work orders as shown in the following list.

170 FirstEnergy's response to Data Request BRC Set-1-INT-029 and 030 - Confidential.
171 FirstEnergy's response to 2018 Data Request BRC Set 8-INT-002.
172 FirstEnergy's response to Data Request BRC Set 4-INT-003.

Table 29: Consolidated Unitization Work Orders

Company	Work Order	Description	Amount
CECO	15821005	CE Consolidated Unitization 2011	$ 1,279.22
CECO	15821024	CE Consolidated Unitization 2012	$ 3,322.12
CECO	15821025	CE Consolidated Unitization 2013	$ 32,845.46
CECO	15821026	CE Consolidated Unitization 2014	$ 2,214.01
CECO	15821027	CE Consolidated Unitization 2015	$ 12,429.15
CECO	15821042	CE Consolidated Unitization 2016	$ 2,616,182.01
CECO	15821043	CE Consolidated Unitization 2017	$ 10,129,886.33
CECO	15821044	CE Consolidated Unitization 2018	$ 5,686,340.50
OECO	15821631	OE Consolidated Unitization 2011	$ 2,245.72
OECO	15821668	OE Consolidated Unitization 2012	$ 13,507.99
OECO	15821669	OE Consolidated Unitization 2013	$ 1,890.86
OECO	15821670	OE Consolidated Unitization 2014	$ 3,414.51
OECO	15821671	OE Consolidated Unitization 2015	$ 185,554.71
OECO	15821682	OE Consolidated Unitization 2016	$ 3,415,753.84
OECO	15821683	OE Consolidated Unitization 2017	$ 11,358,127.28
OECO	15821684	OE Consolidated Unitization 2018	$ 5,687,130.82
TECO	15821685	TE Consolidated Unitization 2011	$ 585.95
TECO	15821690	TE Consolidated Unitization 2012	$ (294.51)
TECO	15821691	TE Consolidated Unitization 2013	$ 265.64
TECO	15821692	TE Consolidated Unitization 2014	$ 608.35
TECO	15821693	TE Consolidated Unitization 2015	$ 78,213.79
TECO	15821700	TE Consolidated Unitization 2016	$ 455,984.69
TECO	15821701	TE Consolidated Unitization 2017	$ 1,575,838.89
TECO	15821702	TE Consolidated Unitization 2018	$ 2,647,872.27
		Total	$ 43,911,199.60

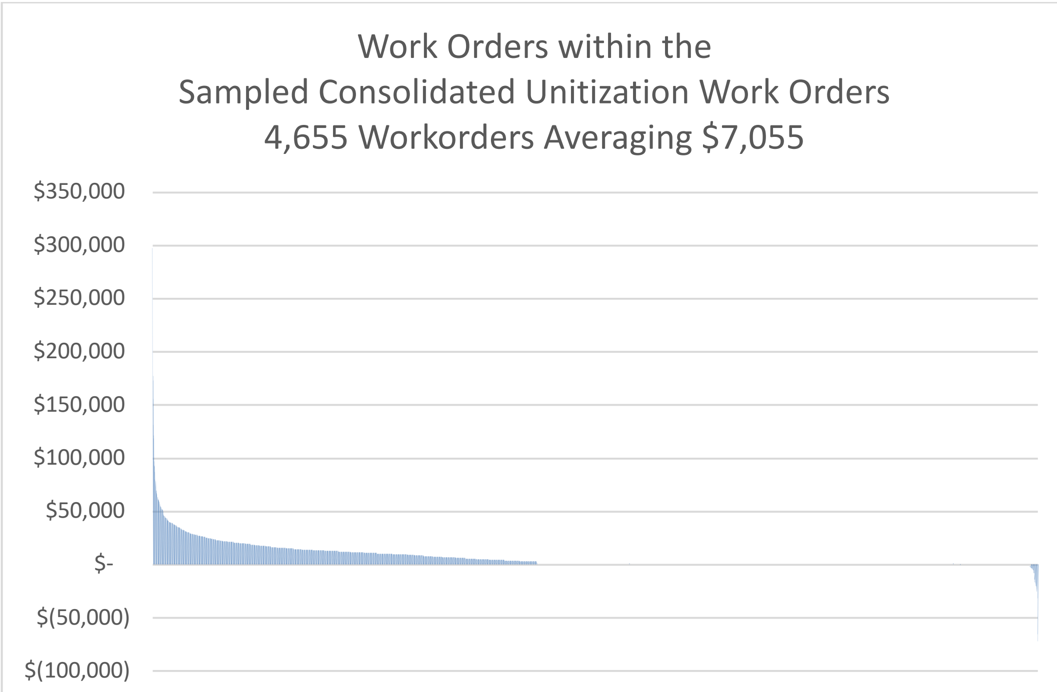
Blue Ridge work order sample testing selected five work orders for further review.

- CECO Work Order 15821042 – CE Consolidation Unitization 2016 - $2,616,282
- CECO Work Order 15821043 – CE Consolidation Unitization 2017 - $10,129,886
- CECO work Order 15821044 – CE Consolidation Unitizations 2018 - $5,686,341
- OECO work Order 15821683 – OE Consolidation Unitizations 2017 - $11,358,127
- TECO work Order 15821701 – TE Consolidation Unitizations 2017 - $1,575,839

For the consolidated unitization in our sample, the Companies provided single-line-item descriptions of the work orders included in the consolidated unitization process, dollars by work order number, and the FERC account.[173] We reviewed the work orders that were consolidated and found that the cost detail included FERC 300 accounts that would typically be considered mass property.[174] We also found that the individual work orders in the consolidation were generally small dollars (averaging $7,055) as shown in the following graph.

[173] First Energy's response to Data Request BRC 12-INT-002.
[174] First Energy's response to Data Request BRC Set 3-INT-001, Attachment 3.

Table 30: Distribution of Consolidated Unitization Work Order Amounts[175]



There were several work orders included within the consolidation in excess of $100,000. Blue Ridge reviewed these work orders and found that, based on the description and type of work, they could reasonably be included in the DCR.

Although the consolidations included mainly small dollar work orders representing mass property, due to the total dollars involved in the consolidation, Blue Ridge considered the potential ramifications of the Companies' approach to yield these findings:

1) The consolidated unitization process can be summarized as follows: Once a project is completed and ready for service, it is moved from CWIP (FERC 107) to Completed Construction Not Classified (FERC 106). AFUDC accruals cease and depreciation is started based on the preliminary FERC 300 charge included in the estimate. The unitization process moves dollars from FERC 106 to Utility Plant in Service (FERC 101) and to the appropriate FERC 300 account. For reporting purposes, both FERC 106 and FERC 101 are considered plant in service.
2) Due to the volume of work orders included in the consolidated unitization, we were unable to confirm that the Companies' unitization resulted in the work orders being unitized to the proper FERC accounts. However, Blue Ridge does not believe that misclassification to the wrong FERC 300 account would be a significant concern as discussed below.

175 WP BRC Set 12-INT-002 CONFIDENTIAL - Consolidated WOs Bar Graphs.

3) Assets were in-service prior to unitization and depreciation had already started. While there is a possibility that a project could be depreciated at the wrong depreciation accrual rate prior to unitization, the projects are individually small and the impact to the reserve would be minimal considering that any adjustment would only be for the incremental difference between one FERC 300 account rate and another.
4) Most Distribution utility projects are considered mass property (e.g., Poles, Overhead and Underground Line Conductors, Line Transformers and Meters). Mass property is depreciated by vintage year and not by individual asset.
5) Since retirements for mass property accounts are done on a curve, the impact to the reserve would be minimal.
6) Any over or under accrual of depreciation would be addressed in regular depreciation studies. The last depreciation study was performed using December 31, 2013, balances, and Blue Ridge recommends that a depreciation study be performed.[176]
7) While plant included in the consolidated unitization process may have been individually small dollars, the Companies process did not identify plant that is recovered through other riders to allow appropriate exclusion for the DCR. As discussed in the Exclusions section of the report, after further review, the Companies found EDR(g) and Experimental Company-Owned LED activity that should have been identified and excluded. While the amounts identified were not significant, it does raise concern about whether the consolidated unitization process could include other plant that should be excluded from the DCR. Blue Ridge recommends that the Companies review the charges reflected in the consolidated unitization to ensure that all plant recovered through other riders is properly identified and excluded from the DCR.

In conclusion, although there may be concern that some minimal amounts related to plant recovered in other riders were not properly identified and excluded from the DCR, Blue Ridge believes that the consolidation unitization process implemented by the Companies has no material effect on the DCR.

Insurance Recoveries

Insurance recoveries can reduce gross plant and should be taken into consideration in the calculation of the DCR. FirstEnergy stated that there were no insurance recoveries charged to capital for the Companies from December 1, 2017, through November 30, 2018.[177] There are also no insurance recoveries pending for the Companies.[178]

Conclusion—Gross Plant in Service

Blue Ridge's review of gross plant through transactional testing and field inspection of the work order sample had several findings that impact the gross plant included in the Rider DCR. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

[176] As part of the Stipulation in Case No. 16-481-EL-UNC, et al., p. 19 (filed 11/9/18), FirstEnergy has agreed to perform a Depreciation Study by June 30, 2023, with a date certain of December 31, 2022. This study would satisfy Blue Ridge's recommendation. However, the Stipulation still awaits Commission approval.
[177] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-020.
[178] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-021.

ACCUMULATED RESERVE FOR DEPRECIATION

F. Determine if the Companies' recovery of the incremental change in Accumulated Reserve for Depreciation are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following accumulated reserve for depreciation ("reserve") incremental change from the prior audit for each company.

Table 31: Incremental Change in Reserve for Depreciation from 11/30/17 to 11/30/18[179]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	(1,329,820,008)	(1,392,028,303)	(62,208,295)
Ohio Edison Company	(1,380,011,274)	(1,450,186,133)	(70,174,859)
The Toledo Edison Company	(604,078,268)	(633,339,860)	(29,261,593)
Total	(3,313,909,549)	(3,475,554,296)	(161,644,747)

The Actual and Estimated Schedules B-3 support the incremental change to the reserve, which provide the reserve for accumulated depreciation balances by FERC account for distribution, subtransmission, general, and intangible plant and for allocated Service Company general and intangible plant. A separate schedule supports the intangible gross plant balances.

Mathematical Verification

Blue Ridge performed mathematical checks on calculations included in the actual and estimated schedules that supported the reserve and checked whether the reserve rolled forward to the revenue requirement calculation correctly. No exceptions were noted.[180]

Source Data Validation

Blue Ridge traced the values used for the actual November 30, 2018, and estimated February 28, 2019, reserve balances to the source documentation. The actual and estimated balances reconciled to the supporting documents.

Impact of Change in Pension Accounting

Similar to the Gross Plant schedules, the reserve balances were adjusted to remove the cumulative pre-2007 impact of a change in pension accounting.

Additional Validation Testing

In addition to reconciling the reserve to supporting documentation, Blue Ridge performed additional analysis to validate the reserve balances. Assets are placed in service primarily as (1) an addition of new assets (for example, a new residential sub-division) or (2) a replacement of existing assets. When assets are replaced, the existing assets are retired. Gross plant in service and the depreciation reserve is reduced to reflect that the assets are no longer in service on the books of the Companies. When assets are replaced, the Companies incur cost of removal and, in some cases, receive salvage for the old assets. Thus, the reserve has three components: (1) accumulated depreciation, (2) cost of removal, and (3) salvage. Cost of removal represents the cost of dismantling,

[179] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[180] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.

demolishing, tearing down, or otherwise removing retired utility plant. Salvage represents the amount received for property retired.

The retirement of assets does not affect net plant in service since the original cost retired reduces gross plant in service and also reduces the reserve. However, the recording of cost of removal decreases the reserve and, therefore, increases net plant in service. Salvage increases the reserve and, therefore, decreases net plant in service.

Of the 58 sampled work orders Blue Ridge obtained as part of the validation testing, 27 work orders were for replacement work, including blanket and project work orders. The Companies provided the cost of the new assets, retirement data, cost of removal, and, if appropriate, salvage for each work order from the PowerPlant Asset Accounting system except for the work orders discussed in testing step T6. Salvage is captured in most instances on an aggregate basis. Scrap is sold from a separate work order to avoid individual scrap transactions and additional paperwork. This procedure is normal for utilities.

Conclusion—Accumulated Reserve for Depreciation

As discussed in testing steps T1 through T10 above, Blue Ridge found adjustments that should be made to the reserve balances to ensure that net plant is appropriately reflected in the DCR. The specific adjustments are also discussed, as necessary, in the Exclusions and Gross Plant in Service subsections. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

ACCUMULATED DEFERRED INCOME TAXES

G. Determine if the Companies' recovery of the incremental accumulated deferred income taxes (ADIT) are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following accumulated deferred income taxes (ADIT) incremental change from the prior audits for each company.

Table 32: Incremental Change in ADIT from 11/30/17 to 11/30/18[181]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	(502,293,445)	(246,517,542)	255,775,903
Ohio Edison Company	(609,321,744)	(307,470,479)	301,851,265
The Toledo Edison Company	(162,103,480)	(77,183,499)	84,919,982
Total	(1,273,718,669)	(631,171,519)	642,547,150

The incremental change is supported by the actual and estimated ADIT Schedules. The schedules include the FERC accounts 281 and 282 Property Accounts. The Companies' ADIT includes the allocation portion of the ADIT attributed to the Service Company.

[181] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.

Authority to Recover ADIT in Rider DCR

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO provide the authority for the inclusion of Accumulated Deferred Income Taxes (ADIT) within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case.[182] [Emphasis added]

During the 2011 audit, Staff further clarified that the treatment of ADIT in the Rider DCR was intended to be the same methodology approved in the last distribution rate case.[183]

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included on the actual and estimated Companies' and Service Company's ADIT Schedules and verified that ADIT rolled forward to the revenue requirement calculation correctly. No exceptions were noted.[184]

Source Data Validation

The ADIT balances included with the Compliance filings reconciled to the supporting documentation.

The significant change in the ADIT balances between November 30, 2017, and November 30, 2018, reflects the Companies' revaluation of ADIT due to the Tax Cuts and Jobs Act (TCJA). The TCJA reduced the federal corporate income tax rate from 35% to 21%. As a result, the ADIT balances as of January 1, 2018, were revalued at that lower rate.

The Companies provided a list of the items included in ADIT for each distribution company and the Service Company.[185] Blue Ridge found the majority of dollars included in ADIT are temporary differences associated with (1) the differences between book and tax depreciation, (2) Section 263A overheads and indirect costs that are required to be capitalized for book purposes and deducted as incurred for tax purposes, and (3) repairs that, for book purposes, are capitalized and depreciated over the life of the asset and, for tax purposes, are allowed to be deducted as repairs. The Companies excluded deferred taxes in CWIP, ADIT associated with future use and non-utility property, ATSI land leases, capital lease vehicles, and Smart Meters/Grid/Software. The Companies also exclude the ADIT associated with Pension Restatement (cumulative 2006). In prior audits, the Companies provided explanations for the items that were not clearly identified as being related to plant in service or were not readily apparent that they should be included in the DCR.[186] Similar items were included in this

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182 Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
183 Blue Ridge's Compliance Audit of the 2011 Delivery Capital Recovery (DCR) Rider, submitted April 12, 2012, page 52.
184 WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
185 FirstEnergy's response to Data Request BRC Set-1-INT-001, Attachment 9—Confidential.
186 FirstEnergy's response to 2018 Data Requests BRC Set-8-INT-002, BRC Set 13-INT-005—Confidential, BRC Set-8-INT-003—Confidential, BRC Set-13-INT-006—Confidential, and BRC Set-8-INT-004 - Confidential.

year's filings. Blue Ridge found that the Companies' explanations regarding how each of the items was related to plant in service or should otherwise be included in the DCR to be not unreasonable.

Conclusion—Accumulated Deferred Income Taxes

Blue Ridge found that the ADIT balances appropriately reflected the change in tax rates from the TCJA. The ADIT descriptions included were consistent with prior filings, were related to plant in service, and are not unreasonable. The Tax Cuts and Jobs Act Effects subsection of this report discusses the Companies' treatment of excess accumulated deferred income taxes (EDIT) arising from the Tax Cuts and Jobs Acts (TCJA).

DEPRECIATION EXPENSE

H. Determine if the Companies' recovery of the incremental depreciation expense are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include incremental depreciation expense for each company from the prior audit as shown in the following table.

Table 33: Incremental Change in Depreciation Expense from 11/30/17 to 11/30/18[187]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	99,292,700	102,103,616	2,810,917
Ohio Edison Company	104,903,818	106,951,437	2,047,619
The Toledo Edison Company	38,953,731	39,729,937	776,205
Total	243,150,250	248,784,991	5,634,741

Schedule B-3.2 for each operating company provides the calculated depreciation expense based on the plant investment. The depreciation (usually referred to as amortization) calculations associated with Other Plant FERC 303 accounts were performed on Schedule Intangible Depreciation Expense Calculation.

Mathematical Verification

The Companies stated the methodology to calculate depreciation expense for OE, CEI, and TE was approved in Case No. 07-551-EL-AIR, and must continue to be used in Rider DCR in order to properly calculate incremental depreciation expense. For the Service Company, the Companies did not have an approved methodology for calculating depreciation expense. The Companies created the Service Company depreciation expense schedules for Rider [DCR] based on net plant in service, which has consistently been used in all Rider DCR filings since inception.[188]

Blue Ridge verified the mathematical accuracy of the depreciation expense calculations and found that the Distribution Companies' depreciation expense was consistent with the methodology used in the last base rate case with the exception of FERC account 390.3. Blue Ridge found that the formula to calculate depreciation expense for FERC account 390.3 for CEI and OE Actual used net plant. The formula using gross plant for the estimated FERC account 390.3 for CEI and OE was

187 WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
188 FirstEnergy's response to 2017 Data Request BRC Set 11-INT-012.

consistent with the other accounts and used gross plant. Since the DCR revenue requirement is driven by estimated balances, there is no effect to the DCR.

The Rider DCR uses gross plant-in-service balances consistent with the last distribution rate case to develop the depreciation expense component of the revenue requirements. Any revisions to gross plant should be flowed through the Rider DCR model to ensure that the appropriate amount of depreciation expense is included within the DCR.

The plant balances used to calculate the depreciation were linked to the plant schedules and no exceptions were noted. The calculated depreciation expense on Schedule B-3.2 and the Intangible Depreciation Schedule rolled forward to the revenue calculation correctly.[189]

Source Data Validation

The depreciation accrual rates used were from the approved depreciation study as part of Case No. 07-551-EL-AIR. The PUCO Staff presented the results of its study in its Staff Report issued on December 4, 2007. The PUCO Order in Case No. 07-551-EL-AIR was issued on January 21, 2009, and directed the Companies to use the accrual rates proposed by the Staff.[190]

Blue Ridge compared the depreciation accrual rates used in the Rider DCR sub-transmission, distribution, and general plant depreciation calculations to the rates within Staff's Reports.[191] Two items were identified and resolved: (1) the Case No. 07-551-EL-AIR Staff Report did not have a balance for CE Account 359 Roads & Trails, so no depreciation accrual rate was provided (CE used the accrual rate from Case No. 89-1001-EL-AIR) and (2) the CE accrual rate for Account 371 Installation on Customer Premises did not agree with the Staff report. Further investigation determined that the Staff Report was corrected during the last distribution case. Both issues were resolved, and the accrual rates used by CE were not unreasonable.

Conclusion—Depreciation Expense

Blue Ridge found that the calculation of depreciation expense was consistent with the methodology used in the last distribution rate case with the exception of FERC account 390.3 CEI and OE Actual. The Rider DCR uses gross plant-in-service balances consistent with the last distribution rate case to develop the depreciation expense component of the revenue requirements. Any revisions to gross plant should be flowed through the Rider DCR model to ensure that the appropriate amount of depreciation expense is included within the DCR.

The depreciation accrual rates used in the Rider DCR are based upon balances as of May 31, 2007. The Companies updated the depreciation study using plant as of December 31, 2013, and provided the updated study to the Commission Staff on June 1, 2015.[192] Since the last depreciation study was based on balances from six years ago, Blue Ridge recommends that the Companies perform a deprecation study.[193] The study would also address any possible concerns associated with the over

[189] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[190] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-022.
[191] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[192] WP FE response to 2015 Data Request BRC Set 1-INT-012—Confidential.
[193] As part of the Stipulation in Case No. 16-481-EL-UNC, et al., p. 19 (filed 11/9/18), FirstEnergy has agreed to perform a Depreciation Study by June 30, 2023, with a date certain of December 31, 2022. This study would satisfy Blue Ridge's recommendation. However, the Stipulation still awaits Commission approval.

or under accrual related to the consolidated unitization process used by the Companies to reduce its unitization backlog.

PROPERTY TAX EXPENSE

I. Determine if the Companies' recovery of incremental property taxes are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following incremental property tax expense for each company from the prior audit.

Table 34: Incremental Change in Property Tax Expense from 11/30/17 to 11/30/18[194]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	108,220,402	112,908,431	4,688,029
Ohio Edison Company	92,264,221	94,527,764	2,263,543
The Toledo Edison Company	30,860,390	31,477,071	616,682
Total	231,345,013	238,913,267	7,568,254

The Actual and Estimated Schedules C-3.10 support the incremental calculation of personal and real property taxes based upon the gross plant for the three operating companies. A separate schedule supports the property tax associated with the Service Company plant in service.

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations and validated that the calculated property taxes rolled forward to the revenue requirement calculation performed correctly. No exceptions were noted.[195]

Source Data Validation

Blue Ridge found the workpapers were well organized and fully sourced. Property tax rates were calculated using the most recent (2018) Ohio Annual Property Tax Return filings and the State of Ohio Assessment. 2018 property tax records.[196] The actual property tax rates were applied to the estimated plant balances to determine the estimated property taxes. The change in property tax rates from 2017 to 2018 were not unreasonable as shown in the following table.

Table 35: Property Tax Rates 2017 and 2018

Description	CE	OE	TE
2017 Property Tax Rates	1.73%	0.94%	1.24%
2018 Property Tax Rates	1.76%	0.93%	1.27%
Difference 2018-2017	0.03%	-0.01%	0.03%
% change	1.98%	-0.99%	2.30%

194 WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
195 WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
196 FirstEnergy's response to 2018 Data Request BRC Set 1-INT-1, Attachment 11-Confidential.

Conclusion—Property Tax Expense

Blue Ridge found that the calculation of property tax is not unreasonable. As the Rider DCR uses plant-in-service balances to develop the property tax component of the revenue requirements, any revisions to gross plant should be flowed through the Rider DCR model to ensure the appropriate amount of property tax is included within the DCR.

SERVICE COMPANY

J. Determine if the Companies' recovery of allocated Service Company plant in service, accumulated reserve, ADIT, depreciation expense, and property tax expense are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following Service Company incremental plant in service, accumulated reserve, ADIT, depreciation expense, and property tax expense for each company.

Table 36: Change in Service Company Rate Base and Expense from 11/30/17 to 11/30/18[197]

Description	CEI	OE	TE	Total
Actual 11/30/18				
Gross Plant	105,485,068	127,829,195	56,268,600	289,582,863
Reserve	59,438,781	72,029,262	31,706,260	163,174,303
ADIT	(286,552)	(347,251)	(152,855)	(786,658)
Rate Base	**46,332,839**	**56,147,184**	**24,715,195**	**127,195,218**
Depreciation Expense	4,224,088	5,118,845	2,253,243	11,596,177
Property Tax Expense	59,056	71,566	31,502	162,125
Total Expenses	**4,283,144**	**5,190,411**	**2,284,746**	**11,758,301**
Actual 11/30/17				
Gross Plant	100,737,744	122,076,281	53,736,249	276,550,274
Reserve	52,490,968	63,609,744	28,000,108	144,100,820
ADIT	8,649,466	10,481,619	4,613,860	23,744,946
Rate Base	**39,597,310**	**47,984,918**	**21,122,281**	**108,704,509**
Depreciation Expense	4,600,244	5,574,680	2,453,895	12,628,819
Property Tax Expense	56,639	68,636	30,213	155,488
Total Expenses	**4,656,883**	**5,643,316**	**2,484,108**	**12,784,307**
Incremental				
Gross Plant	4,747,323	5,752,914	2,532,351	13,032,589
Reserve	6,947,813	8,419,517	3,706,152	19,073,483
ADIT	(8,936,019)	(10,828,870)	(4,766,715)	(24,531,604)
Rate Base	**6,735,529**	**8,162,267**	**3,592,914**	**18,490,710**
Depreciation Expense	(376,156)	(455,835)	(200,652)	(1,032,643)
Property Tax Expense	2,418	2,930	1,290	6,637
Total Expenses	**(373,739)**	**(452,905)**	**(199,362)**	**(1,026,006)**

The Compliance Filings include actual November 30, 2018, and estimated February 28, 2019, schedules that accumulate Service Company general and intangible gross plant, reserve, ADIT, and incremental depreciation and property tax expense that are then allocated to the Companies based upon the allocation factors agreed to within the Combined Stipulation.

Authority to Include Service Company Costs and Support for Allocation Factors

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (reaffirmed in Case Nos. 12-1230-EL-SSO[198] and 14-1297-EL-SSO[199]) provide the authority for the Service Company

[197] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[198] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[199] Case No. 14-1297-EL-SSO Commission Opinion and Order, March 31, 2016, page 119.

allocation factors used within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case.[200] (Emphasis added.)

The following allocation factors were used in Case No. 07-551-EL-AIR[201] and were appropriately used in accordance with the Combined Stipulation to allocate Service Company costs in Rider DCR:

Table 37: Service Company Allocation Factors

	CEI	OE	TE	Total
Allocation Factors	14.21%	17.22%	7.58%	39.01%

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included within the Service Company schedules and verified that allocated items rolled forward to the operating companies' schedules correctly as incremental changes from the values used in the last distribution rate case.[202]

Source Data Validation

The Actual November 30, 2018, and Estimated February 28, 2019, general and intangible gross plant balances, reserve, and ADIT were reconciled to their source documentation.[203]

The Service Company depreciation accrual rates and the property tax rates are based upon the weighted average of the Companies' rates using the authorized allocation factors. The approach is not unreasonable.

Additional Validation Testing

As discussed in the Gross Plant subsection of this report, Blue Ridge performed additional validation testing using selected sample work orders. Service Company work orders were included within the performed testing.

Conclusion—Service Company

Blue Ridge found nothing that would indicate that Service Company costs included within Rider DCR are unreasonable.

COMMERCIAL ACTIVITY TAX AND INCOME TAXES

K. Determine if the Companies' recovery of Commercial Activity Tax (CAT) associated with the revenue requirement are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

[200] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[201] WP FE response to 2011 Audit Data Request BRC-10-10 and 10-11.
[202] WP V&V FE DCR Compliance Filing 01.2.2019—Confidential.
[203] WP V&V FE DCR Compliance Filing 01.2.2019—Confidential.

L. Determine if the Companies' recovery of associated income taxes associated with the revenue requirement are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following incremental commercial activity tax (CAT) for each company. The CAT is calculated based on the statutory 0.26 percent.

Table 38: Incremental Change in CAT from 11/30/17 to 11/30/18[204]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	313,900	399,040	85,140
Ohio Edison Company	324,396	408,510	84,114
The Toledo Edison Company	77,431	101,638	24,207
Total	715,728	909,189	193,461

The Rider DCR Compliance Filings include the following incremental income tax expense for each company.

Table 39: Incremental Change in Income Tax from 11/30/17 to 11/30/18[205]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	9,685,425	9,470,320	(215,105)
Ohio Edison Company	11,817,559	10,990,575	(826,984)
The Toledo Edison Company	1,136,850	1,844,768	707,918
Total	22,639,834	22,305,663	(334,171)

Rider DCR Actual and Estimated Summary Schedules include the calculation for the commercial activity tax and income taxes.

Authority to Include Commercial Activity Tax and Income Tax in Rider DCR

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (reaffirmed in Case Nos. 12-1230-EL-SSO[206] and 14-1297-EL-SSO[207]) provide the authority for the recovery of income taxes and commercial activity tax within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes. . . .[208] (Emphasis added.)

[204] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[205] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[206] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[207] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[208] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.

Mathematical Verification

Blue Ridge performed mathematical checks on the calculation of the commercial activity tax and income tax expense included in the Summary Schedules of the Compliance Filings.[209] No exceptions were noted.

Source Data Validation

FirstEnergy appropriately applied the Commercial Activity Tax (CAT) rate of 0.26% to gross receipts calculated within the Compliance Filings.

The following table shows the composite tax rates used by the Companies' filings. The composite tax rates reflect the effective tax rate for federal income tax and the Ohio, and municipalities' tax rates as of December 31, 2017. The rates are not unreasonable. The rates were applied to equity return component of the DCR revenue requirement.

Table 40: Effective Income Tax Rates Reflected in Companies' Filings for 2017 and 2018[210]

Description	CEI	OE	TE
2018 Effective Income Tax Rates			
Local Effective Tax Rate	1.79%	1.33%	1.08%
Federal Income Tax Rate	21%	21%	21%
2017 Effective Income Tax Rate	22.41%	22.05%	21.85%
2019 Effective Income Tax Rates			
Local Effective Tax Rate	1.98%	1.48%	1.72%
Federal Income Tax Rate	21%	21%	21%
2018 Effective Income Tax Rate	22.57%	22.17%	22.36%

Conclusion—Commercial Activity Tax and Income Taxes

Blue Ridge found that the commercial activity tax and income tax expense were calculated consistently with prior filings and are not unreasonable. Any adjustments discussed in other subsections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

Tax Cuts and Jobs Act Effect

In the 2017 DCR Report, Blue Ridge expressed concerns regarding the Companies' treatment of excess accumulated deferred income taxes (EDIT) arising from the Tax Cuts and Jobs Acts (TCJA). Blue Ridge recommended (1) that the amount by which the ADIT balance is revalued is also the amount by which the Companies' must set up a regulatory liability to refund the excess deferred taxes to ratepayers because the tax future obligation to the federal government decreased by 40% and (2) that the Companies apply the average rate assumption method (ARAM) consistent with normalization requirements to update the regulatory liability to address the timing differences for the property reversal.

[209] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[210] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-31, Attachment 1-Confidential.

The Companies responded to Blue Ridge's recommendations stating that on November 9, 2018, the Companies filed a Stipulation and Recommendation in Case No. 18-1604-EL-UNC ("Stipulation") which resolves the question about the treatment of the excess deferred income tax balances resulting from the TCJA that was raised by Blue Ridge in the above recommendation. The Companies will implement the Stipulation upon Commission approval.[211] As of the drafting of this report, the Stipulation has not yet been approved by the Commission.

Under the Stipulation, Rider DCR rate base will reflect the gross *normalized* property EDIT balance as of December 31, 2017, and the net *non-normalized* property EDIT balance as of the measurement period.

1) Normalized Property: Amortization of the normalized property EDIT balance and the related cumulative reserve will be accounted for in a new credit mechanism. The cumulative reserve in the credit mechanism will accrue a return in the same manner as Rider DCR to make the Companies whole for the gross normalized property EDIT in Rider DCR rate base.
2) Non-Normalized Property: Amortization of the non-normalized property EDIT will flow back to customers via the new credit mechanism, while both the gross balance and cumulative reserve will be accounted for in Rider DCR.

The treatment of the EDIT balances will commence effective January 1, 2018, and will continue until the balances have been fully amortized. The following table presents the audited property EDIT balances as of December 31, 2017, and the Companies' estimated balances in Rider DCR at date of measurement, assuming the Settlement is approved.[212]

Table 41: EDIT Balances to be Reflected in the Rider DCR Under Stipulated Settlement Agreement

		OE	CEI	TE	Total
Audited Balance as of December 31, 2017					
Normalized Property	ARAM	$ (157,240,782)	$ (173,640,455)	$ (42,962,870)	$ (373,844,107)
Non-Normalized Property	10-Year	(89,328,343)	(39,321,477)	(22,284,682)	(150,934,501)
Total EDIT in DCR Rate Base		$ (246,569,125)	$ (212,961,931)	$ (65,247,552)	$ (524,778,608)
Estimated Balance as of November 30, 2018					
Normalized Property	ARAM	$ (157,240,782)	$ (173,640,455)	$ (42,962,870)	$ (373,844,107)
Non-Normalized Property	10-Year	(81,139,911)	(35,717,008)	(20,241,919)	(137,098,839)
Total EDIT in DCR Rate Base		$ (238,380,694)	$ (209,357,463)	$ (63,204,789)	$ (510,942,945)
Estimated Balance as of February 28, 2019					
Normalized Property	ARAM	$ (157,240,782)	$ (173,640,455)	$ (42,962,870)	$ (373,844,107)
Non-Normalized Property	10-Year	(78,906,703)	(34,733,971)	(19,684,802)	(133,325,476)
Total EDIT in DCR Rate Base		$ (236,147,485)	$ (208,374,426)	$ (62,647,672)	$ (507,169,583)

Conclusion—Tax Cuts and Jobs Act Effect

Blue Ridge finds the resolution of the EDIT matter from the prior DCR audit not unreasonable. The property EDIT balances, normalized and non-normalized, will be accounted for between the

[211] FirstEnergy's response to Data Request BRC Set 1-INT-017, Item #17.
[212] FirstEnergy's response to Data Request BRC Set 6-INT-002, Attachment 1 and WP EDIT Set6-INT-002 Attachment 1 Confidential.

Rider DCR and credit mechanisms. Until this adjustment is made, the DCR rate base is overstated. Thus, Blue Ridge recommends that the EDIT balances be reflected within the DCR and the overcollection due to the delay in recording the EDIT in the DCR be adjusted within the next DCR filing. Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(20,849,697) for CECO, $(23,547,507) for OE, and $(6,257,130) for TE [**ADJUSTMENT #9**].

Return

M. Determine if the Companies return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following calculated return on rate base at 8.48% for each company.

Table 42: Incremental Change in Return on Rate Base from 11/30/17 to 11/30/18[213]

Company	11/30/2017	11/30/2018	Incremental
The Cleveland Electric Illuminating Company	28,183,288	53,560,482	25,377,194
Ohio Edison Company	34,828,839	63,612,126	28,783,288
The Toledo Edison Company	3,374,926	10,560,235	7,185,309
Total	66,387,052	127,732,843	61,345,791

The Rider DCR Summary Schedule includes the calculation for the rate of return and the return on plant using the calculated rate base.

Authority to Collect a Return on Plant-in-Service in Rider DCR

The Combined Stipulation and Order in Case No. 10-0388-EL-SSO (and reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO[214]) provides the capital structure, cost of debt, and return on equity that is allowed in Rider DCR Revenue Requirements. Section B.2 states the following:

> The return earned on such plant will be based on the cost of debt of 6.54% and a return on equity of 10.5% determined in the last distribution rate case utilizing a 51% debt and 49% equity capital structure. [215]

Mathematical Verification

The rate of return and the return on plant is calculated correctly in accordance with the Combined Stipulation.[216]

Source Data Validation

The capital structure and rates used within Rider DCR agree with the stipulated amounts.

[213] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[214] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[215] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[216] WP V&V FE DCR Compliance Filing 1.2.2019-Confidential.

Conclusion—Return

Although the adjustments discussed in other subsections of this report will affect the final return included within the DCR, Blue Ridge found that the calculation of the return component of the DCR is not unreasonable.

RIDER DCR CALCULATION

N. Determine if the Companies' revenue requirement calculation for Rider DCR are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Compliance Filing Summary Schedules pull together the various components allowed within Rider DCR and calculate the revenue requirements based upon the actual November 30, 2017, and estimated February 28, 2018, balances. The Annual Rider DCR Revenue is compared against the Commission-approved Revenue Cap in the Companies' filings.[217]

Mathematical Verification

The various actual November 30, 2018, and estimated February 28, 2019, components, including gross plant, reserve, ADIT, depreciation, and property tax expense, were discussed in other subsections of this report and roll forward into the revenue requirements. The calculations are correct.

Annual Cap

Recovery through the DCR is subject to annual caps. The annual cap has been modified several times since the inception of the Rider DCR. The cap for the filing under review is a composite from two stipulations approved by the Commission.

The Stipulation in Case No. 12-1230-EL-SSO modified the annual cap of the Rider DCR Revenue collected effective June 1, 2014, as follows:

> For the twelve-month period from June 1, 2014, through May 31, 2015, that Rider DCR is in effect, the revenue collected by the Companies shall be capped at $195 million, <u>for the following twelve-month period, the revenue collected under Rider DCR shall be capped at $210 million</u> [emphasis added].[218]

The Stipulation in Case No. 14-1297-EL-SSO modified the annual cap of the Rider DCR Revenue collected as follows:

> The revenue caps for the Delivery Capital Recovery Rider (Rider DCR) <u>will increase annually to $30 million for the period of June 1, 2016, through May 31, 2019</u>; $20 million for the period of June 1, 2019, through May 31, 2020; and $15 million for the period of June 1, 2022, through May 31, 2024.[219]

[217] CEI, OE, and TE Rider DCR Replacement Compliance Filings dated 1/12/18, page 57.
[218] Case No. 12-12-1230-EL-SSO Opinion and Order, July 18, 2012, page 10.
[219] Case No. 14-1297-EL-SSO Opinion and Order, March 31, 2016, page 25.

The Companies appropriately applied the annual caps in the stipulations in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO that resulted in an annual cap for the 2018 DCR as follows:

Table 43: Companies' Calculation of Annual Cap Prior to Under (Over) Recovery Adjustment[220]

12 months 6/1/15- 5/31/16		$ 210,000,000
12 months 6/1/16- 5/31/17		30,000,000
12 months 6/1/17- 5/31/18		30,000,000
12 months 6/1/18-5/31/19	$ 30,000,000	
Prorated for seven months		$ 17,500,000
		$ 287,500,000

<u>Over/Under Recovery</u>

The Stipulations in Case Nos. 10-388-EL-SSO and 12-1230-EL-SSO contain similar language addressing over or under recoveries against the annual caps as follows:

> For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap.[221]

The January 2, 2019, Rider DCR Replacement Compliance Filing cover letters state, "The attached schedules demonstrate that the year-to-date revenue is below the permitted cap for 2018." Blue Ridge confirmed that the Companies have not exceeded the Commission-approved DCR Revenue Cap.

The annual cap analysis included in the January 2, 2019, filing included revenues through November 30, 2018. Using the actual annual revenue through December 31 for years 2016 and 2017, the Companies have a cumulative under recovery of $17,718,063 as shown in the following table.[222]

Table 44: Annual DCR Revenues Vs. Annual Cap through November 30, 2018

Period	Annual Cap	Annual Revenue	Under (Over)	Cum Under (Over)
2012	$ 150,000,000	$ 128,616,253	$ 21,383,747	$ 21,383,747
2013	$ 165,000,000	$ 185,631,927	$ (20,631,927)	$ 751,820
2014	$ 188,750,000	$ 191,709,557	$ (2,959,557)	$ (2,207,737)
2015	$ 203,750,000	$ 207,078,057	$ (3,328,057)	$ (5,535,794)
2016	$ 227,500,000	$ 216,681,105	$ 10,818,895	$ 5,283,100
2017	$ 257,500,000	$ 262,678,121	$ (5,178,121)	$ 104,979
2018	$ 287,500,000	$ 269,886,915	$ 17,613,085	$ 17,718,063

[220] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.
[221] Case No. 10-0388-EL-SSO Opinion and Order, August 25, 2010, page 12 and Case No. 12-12-1230-EL-SSO Opinion and Order, July 18, 2012, page 10.
[222] WP V&V FE DCR Compliance Filing 1.2.2019—Confidential.

In addition to the total cap, the Companies have individual annual caps that limit recovery through the Rider DCR. The following table shows the Companies' revenue to the aggregate annual cap (adjusted for the cumulative under [over] recovery) and the allocated Companies' caps. Blue Ridge confirmed the Actual Revenue through November 30, 2018, included in the Companies' filing.[223] Each of the operating companies' DCR revenues through November 30, 2018, are below the annual cap.

Table 45: 2018 Annual DCR Revenue to Aggregate and Allocated Caps through November 30, 2018[224]

Period	Aggregate Annual Cap	CEI	OE	TE
% of Aggregate Annual Cap		70%	50%	30%
2018 Annual Cap	$ 287,500,000			
Cumulative Under (Over)-2016	$ 104,979			
Adjusted 2018 Annual Cap	$ 287,604,979	$ 201,323,485	$ 143,802,489	$ 86,281,494
Annual Revenue Through 11/30/2018	$ 269,886,915	$ 117,163,203	$ 122,300,842	$ 30,422,870
Under (Over) 2018 Revenue Cap	$ 17,718,064	$ 84,160,281	$ 21,501,646	$ 55,858,623

Slight difference due to rounding

Conclusion—Rider DCR Calculation

Although Blue Ridge found that the balances used in the Rider DCR calculations should be adjusted, Blue Ridge found that the Rider DCR revenue requirements calculation is not unreasonable.

The Annual Rider DCR Revenue through November 30, 2018, is under both the aggregate annual cap and the allocated annual cap by company.

PROJECTIONS

O. Develop an understanding of the projection methodology used by the Companies for plant-in-service, property taxes, Commercial Activity Tax, and Income Tax

The Compliance Filings include projections for the first two months in 2019. To develop the first quarter 2019 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2019, the most recent (December 2018) forecast from PowerPlant. The estimated February 28, 2019, plant and reserve balances were then adjusted to reflect current assumptions (including project additions and delays), to incorporate recommendations from prior Rider DCR Audit Reports, and to remove the pre-2007 impact of a change in pension accounting.[225]

Authority to use Projected Data

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO and continued in Case Nos. 12-12-1230-EL-SSO and 14-1297-EL-SSO provide the authority to include estimated balances in Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

[223] FirstEnergy's response to 2018 Data Request BRC Set 2-INT-009 - Confidential.
[224] WP V&V FE DCR Compliance Filing 01.12.2018—Confidential.
[225] FirstEnergy's response to 2018 Data Request BRC Set 1-INT-001, Attachment 3—Confidential.

> The quarterly filings will be based on estimated balances as of August 31, November 30, February 28, and May 31, respectively, with any reconciliation between actual and forecasted information being recognized in the following quarter.[226]

Mathematical Verification and Source Validation

The actual and estimated schedules in the Compliance Filings used the same format and calculations for each of the components and the revenue requirements calculations. Blue Ridge reviewed the estimated February 28, 2019, schedules while performing specific tasks in each of the previous subsections. Specific observations and findings are discussed in the appropriate subsections.

Conclusion—Projections

Blue Ridge found that the projected amounts included through February 2018 are not unreasonable. In addition, the projected amounts will be reconciled to the actual amounts, and the Rider DCR revenue requirement will be adjusted to actual in the next quarter's Rider DCR Compliance Filings.

OVERALL IMPACT OF FINDINGS ON RIDER DCR REVENUE REQUIREMENTS

P. Determine the impact of all findings to Rider DCR revenue requirements.

Blue Ridge's review found several items that have an impact on Rider DCR Revenue Requirements, including adjustments for plant recovered through other riders that were not excluded in the Companies' consolidated unitization process, vegetation management expenditures that should not be charged to plant, overstated plant balances due to delays or incorrect in-service dates or retirements not recorded timely, and failure to record a regulatory liability to reflect a refund of the excess deferred taxes owed to ratepayers because the Companies historically collected federal tax expense at 35% but will later pay the deferred portion to the federal government at 21%. The flow through of these adjustments has the following impact on the DCR.

Table 46: Impact of Blue Ridge's Findings on Rider DCR Revenue Requirement[227]

[226] Case No. 12-1230-EL-SSO Stipulation and Recommendation April 13, 2012, page 22.
[227] WP FEOH 2018 Adjustments to Plant and Reserve-Confidential and WP Impact of Adjustments BRC Set1-INT-001 Attachment 1 – FE DCR Compliance Fling 1.2.22019—Confidential.

Adj #	Description	CEI	OE	TE	Total
	As Filed	$ 156,274,362	$ 161,373,970	$ 40,236,054	$ 357,884,386
1	EDR(g) Not Excluded (Consolidated Unitization)	(3,085)	-	-	(3,085)
2	Deleted		-	-	
3	LED Not Excluded (Consolidated Unitization)	165	33	(12,021)	(11,823)
4	Vegetation Mgmt-Expense	(1,786,623)	(1,141,265)	(364,336)	(3,292,224)
5, 6	Wrong In-Service Date, AFUDC Overstated	-	(37,042)	-	(37,042)
7	Retirements Not Recorded Timely	-	(4,312)	-	(4,312)
8	Delay in Closing, AFUDC Overstated	-	(3,227)	-	(3,227)
9	EDIT Regulatory Liability	(20,849,697)	(23,547,507)	(6,257,130)	(50,654,334)
	Impact of All Adjustments	(22,639,240)	(24,733,321)	(6,633,488)	(54,006,048)
	Recommended Rider DCR Revenue Requirements	$ 133,635,123	$ 136,640,649	$ 33,602,566	$ 303,878,338

APPENDICES

Appendix A: Rider DCR Excerpts within Stipulations and Order

Appendix B: Abbreviations and Acronyms

Appendix C: Data Requests and Information Provided

Appendix D: Workpapers

APPENDIX A: RIDER DCR EXCERPTS WITHIN ORDER AND COMBINED STIPULATION

Excerpts from the Commission Opinion and Order and the Combined Stipulation specifically related to Rider DCR are provided below.

Case No. 10-388-EL-SSO Commission Opinion and Order

On August 25, 2010, the Commission issued its Opinion and Order regarding Case No. 10-388-EL-SSO. The Order approved the following Stipulation Agreements with modifications:

- Original Stipulation Agreement included with the Companies' Application dated March 23, 2010
- First Supplemental Stipulation Agreement dated May 13, 2010 which modified the terms of the original stipulation
- Second Supplemental Stipulation dated July 19, 2010

The original stipulation and two supplemental stipulations are collectively referred to as the Combined Stipulation, which addressed all the issues within the case. The Commission's Order included several references to the Deliver Capital Recover Rider (DCR), which is the subject of this report. Those excerpts are provided as follows:

Order, pages 11-12 B. Summary of the Combined Stipulation:

(13). Effective January 1, 2012, the Delivery Capital Recovery Rider (Rider DCR) will be established to provide the Companies with the opportunity to recovery property taxes, commercial activity tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in *In re FirstEnergy*, Case No. 07-551-EL-AIR, et al, Opinion and Order (January 21, 2009). The return earned on such plant will be based on the cost of debt of 6.54 percent and a return on equity of 10.5 percent determined in that proceeding utilizing a 51 percent debt and 49 percent equity capital structure (*id*. at 13-14).

For the first twelve months Rider DCR is in effect, the revenue collected by the Companies shall be capped at $150 million; for the following 12 months, the revenue collected under Rider DCR shall be capped at $165 million; and for the following five months, the revenues collected under Rider DCR shall be capped at $75 million. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be excluded from Rider DCR and the annual cap allowance. Net capital additions for plant in service for general plant shall be included in Rider DCR provided that there are no net job losses at the Companies as a result of involuntary attrition due to the merger between FirstEnergy Corp. and Allegheny Energy, Inc. (*id*. at 14-15).

Rider DCR will be adjusted quarterly, and the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of Section 4909.18, Revised Code. The first quarterly filing will be made on or about October 31, 2011, based upon an estimated balance as of December 31, 2011, with rates effective for bills rendered as of January 1, 2012. For any year that the Companies' spending would produce

> revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap (*id*. at 15-17).

Order, page 25, 2. “Does the settlement, as a package, benefit ratepayers and the public interest?”
a. Summary of the Parties’ Arguments.

> FirstEnergy further notes that the proposed ESP would replace its existing Rider DSI with the Rider DCR; FirstEnergy contends that Rider DCR will provide for important investments in the Companies' distribution infrastructure and that Rider DCR incorporates additional customer and regulatory improvements over Rider DSI (Staff Ex. 2 at 4). FirstEnergy notes that Staff and other Signatory Parties will have the opportunity to review quarterly updates to Rider DCR and to participate in an annual audit process (Co. Ex. 4 at 18; Tr, I at 225-227).

And on page 27.

> Moreover, Staff claims that Rider DCR will recover costs, subject to revenue requirement caps each year, associated with actual investments in the Companies’ distribution system. All revenue associated with Rider DCR will be included as revenue in the return on equity calculation for purposes of the SEET test and will be eligible for refund.

Order, page 35, “Does the settlement, as a package, benefit ratepayers and the public interest?”
b. Commission Decision

> The Commission also believes that the Combined Stipulation should be modified with respect to the provision that net capital additions for plant in service for general plant shall be included in Rider DCR so long as there are no net job losses at "the Companies" as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. 0oint Ex. 1 at 15). According to testimony at the hearing, this provision does not cover employees of FirstEnergy Service Company (Tr. I at 85-86). However, many functions for the Companies are performed by employees of the FirstEnergy Service Company (Co. MRO Ex. 6 at 4-5). Therefore, the Commission will modify the Combined Stipulation to include employees of FirstEnergy Service Company who provide support for distribution services provided by OE, CEI, and TE and are located in Ohio within the meaning of "no net job losses" in the Combined Stipulation.
>
> Further, the Commission will clarify that the second paragraph on page 15 of the original stipulation will be replaced by the new language contained in the second supplemental stipulation joint Ex. 1 at 15; Joint Ex. 3 at 4).

And on page 36.

> As agreed to by the signatory parties, approval of Rider DCR, which will not be implemented until January 1, 2012, is in recognition of the Companies' commitments to freeze base distribution rates through May 31, 2014, and to forgo recovery of a minimum of $360 million of legacy RTEP charges (Co. Ex. 12 at 2, 4; Joint Ex. 3 at 6) as well as approximately $42 million in MISO exit fees and PJM integration charges (Staff Ex. 1 at 4).

Order, page 37, 3. "Does the settlement violate any important regulatory principle or practice?"
a. Summary of the Parties' Arguments.

> According to Staff, the proposed ESP improves the CBP used in the current ESP, and, in Rider DCR, provides for a mechanism to expedite funding for reliability enhancements.

And on page 38.

> OCEA also claims that provisions of the Combined Stipulation related to Rider DCR violate regulatory principles and practices. These provisions include the provision that states that updated filings shall not be considered to be "an application to increase rates" within the meaning of Section 4909.18, Revised Code (OCC Ex. 2 at 14). OCEA also cites to the provision of the Combined Stipulation which provides for participation in the audits for the DCR by Staff and other Signatory Parties but does not mention other interested parties (OCC Ex. 2 at 16).

Order, page 40, 3. "Does the settlement violate any important regulatory principle or practice?"
b. Commission Decision

> With respect to OCEA's claim that the provisions related to Rider DCR violate important regulatory principles and practices, the Commission expects that reasonable management will carry out the investments funded by Rider DCR in a manner to achieve significant improvements in distribution reliability and energy efficiency in order to facilitate Ohio's effectiveness in the global economy. Section 4928.02(N), Revised Code. Further, the Commission finds that the provision of the Combined Stipulation which clarifies that the quarterly updates to Rider DCR are not "applications for an increase in rates" subject to the requirements of Section 4909.18, Revised Code, was filed as part of an application submitted pursuant to Section 4928.143, Revised Code. The statutory authority to file an application under Section 4928.143, Revised Code is separate and independent from the statutory provisions of Section 4909.18, Revised Code. OCEA has cited to no previous decision by the Commission or the Ohio Supreme Court holding that adjustments to riders authorized under an ESP must be filed pursuant to Section 4909.18, Revised Code,
>
> OCEA also objects to the provision of the Combined Stipulation which provides for participation in the audits for Rider DCR by Staff and other Signatory Parties. The Commission finds that the Signatory Parties negotiated in good faith for the right to participate in the DCR audits. Nothing in the Combined Stipulation precludes FirstEnergy from including non-signatory parties hi the audit process, and OCEA is free to negotiate with FirstEnergy for the right to participate along with the Signatory Parties. Further, OCEA will have the opportunity to fully participate in any Commission proceeding resulting from the audit process, including ample rights for discovery.

And on page 41.

> Direct Energy states that there is no evidence in the record the Commission has examined the reliability of FirstEnergy's distribution system for the proposed ESP. The Commission finds that Direct Energy's reliance upon Section 4928,143 (B) (2) (h), Revised Code, is misplaced. The provisions of the Combined Stipulation related to Rider DCR were not filed under Section 4928.143(B)(2)(h), Revised Code;

therefore, there is no requirement to conduct an examination of the reliability of FirstEnergy's distribution system.

The Commission also considered the question: "Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. On page 43, OCC witness Gonzalez net present value analysis of the proposed ESP compared to an MRO combined with a potential distribution rate case for the Companies based upon three alternative scenarios. The scenarios included assumptions regarding the DCR, based upon Company witness Ridmann's testimony. First Energy responds that Mr. Gonzalez's testimony is flawed. The Commission found that the assumptions underlying OCC witness Gonzalez's testimony were arbitrary and unrealistic.

Page 47 stated, it is, therefore, ordered that the Combined Stipulation, as modified by the Commission, be adopted and approved.

Combined Stipulation

The Combined Stipulation are comprised of the following documents:

- Original Stipulation Agreement included with the Companies' Application dated March 23, 2010
- First Supplemental Stipulation Agreement dated May 13, 2010 which modified the terms of the original stipulation
- Second Supplemental Stipulation dated July 19, 2010

The key sections related to the scope of this audit from the Combined Stipulation follow:

B. Distribution

Section 2 Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plants including allocated general plant from FirstEnergy Service Company that supports the Companies, which was not included in the rate base determined in the Opinion and Order of January 21, 2009 in Case No. 07-551-EL-AIR et al. ("last distribution rate case"). The return earned on such plant will be based on the cost of debt of 6.54% and a return on equity of 10.5% determined in the last distribution rate case utilizing a 51% debt and 49% equity capital structure. The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case. Rider DCR shall be adjusted quarterly to reflect in-service net capital additions and encourage investment in the delivery system. For the first 12 months Rider DCR is in effect, the revenue collected by the Companies under Rider DCR shall be capped at $150 million; for the following 12 months the revenue collected by the Companies under Rider DCR shall be capped at $165 million, and for the following five months the revenue collected by the Companies under Rider DCR shall be capped at $75 million. Consistent with the time periods for the revenue caps established above, each individual Company will have a cap of 50%, 70% and 30% for Ohio Edison, CEI and Toledo Edison, respectively, of the total aggregate caps as established above. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance. Revenue requirements will be derived for each company separately, and on that basis the recovery of the revenue among the classes of each Company will be calculated using the same methodology as the existing DSI Rider. To effect the quarterly adjustments, the Companies will submit a filing that contains the adjustment requested, the resulting rate for each customer class and the bill impact on customers. The filing shall show the Plant in Service account balances and accumulated depreciation reserve balances compared to that approved in the last distribution rate case. The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case. Net capital additions for plant in Service for General Plant shall be included in the DCR so long as there are no net job losses at the Companies as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. For each account title the Companies shall provide the plant in service and accumulated depreciation reserve for the period prior to the adjustment period as well as during the adjustment period. The filing shall also include a detailed calculation of the depreciation expense and accumulated depreciation impact as a result of the capital additions. The Companies will provide the information on an individual Company basis.

(Section 2 Second paragraph of original text replaced by Second Supplemental Stipulation) The Signatory Parties agree that the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of R.C. § 4909.18 and each Signatory Party further agrees it will not advocate a position to the contrary in any future proceeding. The first quarterly filing will be made on or about October 31, 2011, based on an estimated balance as of December 31, 2011 with rates effective on January 1, 2012 on a bills rendered basis. Thereafter, quarterly filings will be made on or about January 31, April 30, July 30, and October 31 with rates effective on a bills rendered basis effective April 1, July 1, October 1, and January 1, respectively. The quarterly filings will be based on estimated balances as of March 31, June 30 September 30, and December 31, respectively, with any reconciliations between actual and forecasted information being recognized in the following quarter. The Companies will bear the burden to demonstrate the accuracy of the quarterly filings. Upon the Companies meeting such burden, any party may challenge such expenditures with evidence. Upon a party presenting evidence that an expenditure is unreasonable, it shall be the obligation of the Companies to demonstrate that the expenditure was reasonable by a preponderance of the evidence. An annual audit shall be conducted by an independent auditor. The independent auditor shall be selected by Staff with the consent of the Companies, with such consent not being unreasonably withheld. The expense for the audit shall be paid by the Companies and be fully recoverable through Rider DCR. The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable and will be conducted following the Companies' January 31,2012, January 31,2013 and January 31, 2014 filings, and one final audit following the Companies' July 30, 2014 final reconciliation filing. For purposes of such audits and any subsequent proceedings referred to in this paragraph, the determination of whether the amounts for which recovery is sought are not unreasonable shall be determined in light of the facts and circumstances known to the Companies at the time such expenditures were committed. Staff and Signatory Parties shall file their recommendations and/or objections within 120 days after the filing of the application. If no objections are filed within 120 days after the filing of the application, the proposed DCR rate will remain in effect without adjustment, except through the normal quarterly update process or as may be ordered by the Commission as a result of objections filed in a subsequent audit process. If the Companies are unable to resolve any objections within 150 days of the filing of the application, an expedited hearing process will be established in order to allow the parties to present evidence to the Commission regarding the conformance of the application with this Stipulation, and whether the amounts for which recovery is sought are not unreasonable.

For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, as established above, then the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap. In no event will authorization exist to recover in the DCR any expenditures associated with net plant in service additions made after May 31, 2014.

Section 3: Any charges billed through Rider DSI prior to January 1, 2012 shall not be included as revenue in the return on equity calculation for the Companies for purposes of applying the Significantly Excessive Earnings Test ("SEET"), nor considered as an adjustment eligible for refund. Any charges billed through Rider DCR after January I, 2012 will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. For each year during the period of this ESP, adjustments will be made to exclude the impact: (i) of a reduction in equity resulting from any write-off of goodwill, (ii) of deferred carrying charges, and (iii) associated with any additional liability or write-off of regulatory assets due to implementing this ESP. The significantly excessive earnings test applicable to plans greater than three years and set forth in R.C. § 4928.143(E) is not applicable to this three-year ESP.

D. Continuance of Existing Tariff Riders and Deferrals, Section 3

The following new tariff riders are attached as part of Attachment B, with such new tariffs approved as part of this ESP:

Rider DCR Delivery Capital Recovery (Discussed in Section B.2 above)

H. Other Issues

Section 1: The Companies' corporate separation plan in Case No. 09-462-EL-UNC shall be approved as filed. However, within six months after the completion of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. or within 18 months after this Stipulation is approved, whichever comes first, if the Companies' corporate or operational structure has changed, then the Companies shall file an updated corporate separation plan. In either case whether an updated corporate separation plan is filed or not, this plan may be audited by an independent auditor. The Commission shall select and solely direct the work of the auditor. The Companies shall directly contract for and bear the cost of the services of the auditor chosen by the Commission. Staff will review and approve payment invoices submitted by the consultant.

Section 5: With respect to the recent announcement of the combination of FirstEnergy Corp. and Allegheny Energy, Inc., the Signatory Parties agree that the Commission should not assert jurisdiction and review the merger, and further agree and recommend that the Commission should not in this instance initiate its own review of the merger in light of the facts that the merger is the result of an all stock transaction and there is no change in control of the Companies. Approval of the Stipulation by the Commission indicates acceptance of the Signatory Parties' recommendation.

Case No. 12-1230-EL-SSO Commission Opinion and Order

On April 13, 2012, FirstEnergy filed an application to provide for a standard service offer (SSO) for an electric security plan (ESP). The parties agreed to a Stipulation (ESP 3) that extended the Combined Stipulation for an additional two years. The Commission approved the Stipulation, with modifications, on July 18, 2012. In regards to the Delivery Capital Recovery Rider (Rider DCR), the Order stated.

Order, page 10-11, B. Summary of the Stipulation:

(13). The Delivery Capital Recovery Rider (Rider DCR) will continue to be in effect to provide the Companies with the opportunity to recover property taxes, commercial activity tax, and associated income taxes, and earn a return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in *In re FirstEnergy*, Case No. 07-551-EL-AIR, et al., Opinion and Order (January 21, 2009). The return earned on such plant will be based on the cost of debt of 6.54 percent and a return on equity of 10.5 percent determined in that proceeding utilizing a 51 percent debt and 49 percent equity capital structure. (*Id* at 19.)

For the twelve-month period from June 1, 2014, through May 31, 2015, that Rider DCR is in effect, the revenue collected by the Companies shall be capped at $195 million, for the following twelve-month period, the revenue collected under Rider DCR shall be capped at $210 million. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be excluded from Rider DCR and the annual cap allowance. Net capital additions for plant-in-service for general plant shall be included in Rider DCR provided that there are no net job losses at the Companies as a result of involuntary attribution due to the merger between FirstEnergy Corp. and Allegheny Energy, Inc. (*Id*. At 20-21.)

Rider DCR will be updated quarterly, and the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of Section 4909.18, Revised Code. The first quarterly filing will be made on or about April 20, 2014, based upon the actual plant-in-service balance as of May 31, 2014, with rates effective for bills rendered as of June 1, 2014. For any year that the Companies' spending would produce revenues in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenues collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap. (*Id*. At 23).

(14). Any charges billed through Rider DCR will be included as revenue in the return on equity calculation for purposes of the SEET test and will be considered an adjustment eligible for refund (*Id* at 23).

Order, page 27, 2. "Does the settlement, as a package, benefit ratepayers and public interests?"
Page 28-29, a. General Arguments

Regarding distribution, FirstEnergy contends that the distribution provisions of the ESP 3 will provide additional certainty and stability to customer rates because the ESP 3 continues the distribution rate freeze instituted by the ESP 2 Case through May 31, 2016, except for certain emergency conditions provided for by Section 4909.16, Revised Code (Co. Ex. 3 at 12-13). FirstEnergy further notes that the ESP 3 would continue to provide for investments in the Companies' distribution infrastructure by continuing Rider DCR through the ESP 3 period, which would also be capped (Co. Ex. 1, Stip. at 18-20; Co. Ex. 3 at 14). Additionally, the Companies point out that Staff and other signatory parties would have the opportunity to review quarterly updates and participate in an annual audit process (Co. Ex. 1, Stip. at 21-23).

And on page 33-34, c. Distribution Rate Freeze and Rider DCR

OCC/CP argue that the continued use of Rider OCR is not in the public interest. Initially, OCC/CP admit that Ohio law provides an opportunity for an electric distribution utility (EDU) to request recovery for distribution expenditures as part of an ESP proposal under Section 4928.143(B)(2)(h), Revised Code. However, OCC/CP note that the statute also requires the Commission to review the reliability of the EDU's distribution system to ensure that customers' and the EDU's expectations are aligned and that the EDU is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system. Here, OCC/CP argue that the Companies have failed to provide the information necessary for the Commission to complete this review. OCC/CP contend that testimony presented by Staff witness Baker demonstrated that the reliability standards were achieved in 2011 but did not correlate the Companies' reliability performance in 2011 to the Rider DCR recovery sought in the proposed ESP 3. Further, OCC/ CP argue that the evidence submitted on customer expectations utilized reliability standards established in 2009 or 2010 compared to the Companies' actual performance in 2011 (Staff Ex. 2 at 5; Tr. II at 221-222). OCC/CP state that this information will be "stale" at the beginning of the term of the proposed ESP 3. Further, OCC/CP argue that the Companies' and customers' expectations are not aligned, that the resources the Companies have dedicated to enhance distribution service are excessive, and that there is no remedy to address excessive distribution-related spending in the annual Rider DCR audit cases.

Similarly, NOPEC/NOAC argue that the ESP 3 proposal does not benefit ratepayers and the public interest because residential and small commercial customers will be negatively affected by increases of approximately $405 million in the amount of distribution improvement costs proposed to be recovered through Rider DCR.
AEP Retail also argues that the "cap" on recovery under Rider DCR under the Stipulation may provide a benefit, or may not, depending on the amounts FirstEnergy invests in distribution over the ESP 3 period. However, AEP Retail claims that the Companies have failed to introduce evidence concerning their anticipated distribution investments or accumulated depreciation, making it impossible for the Commission to evaluate this claimed benefit.

OSC contends that Rider DCR recovery is only limited by certain revenue caps and could total $405 million during the period of the proposed ESP 3. OSC argues that, instead of Rider DCR, the Companies should be required to file a formal distribution rate increase case, as, in the past, the Commission has not awarded the Companies the full amount of the requested increase for distribution-related investments. Distribution Rate Case, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48.

The Companies respond that the reliability information utilized in this proceeding was not "stale," citing the fact that OCC witness Gonzales admitted that the Companies' reliability performance standards are not required to be updated (Tr. III at 117-118). Further, the Companies point out that they are also not required by statute to prove that additional investments in the system will impact reliability performance or demonstrate that the Companies' reliability performance and customers' expectations for a proposed ESP are aligned. The Companies also argue that OCC/CP and OSC's claims that the Companies have proposed to recover $405 million as increased distribution revenue recovery is wrong. The Companies proffer that the ESP 3 proposes that recoveries under Rider DCR be capped, and that the caps are proposed to increase by $15 million on an annual basis, identical to the annual increases in the ESP 2 Case (Co. Ex. 3 at 14). The Companies state that this increase in the amount of the caps represents a cumulative $45 million increase over the caps allowed in the ESP 2 Case. Further, the Companies note that, as stated in the Stipulation, they will be required to show what they spent and why it is appropriate to recover these investments through Rider DCR and that the recovery will also be subject to an annual audit.

The Commission finds that the Companies have demonstrated the appropriate statutory criteria to allow continuation of Rider DCR as proposed in the Stipulation. As discussed in Staff's testimony, Staff examined the reliability of the Companies' system and found that the Companies complied with the applicable standards (Staff Ex. 2 at 5-6). Further, the Stipulation provides for an annual audit of recovery under Rider DCR and requires the Companies to demonstrate what they spent and why the recovery sought is not unreasonable. Additionally, the Commission notes that the caps on Rider DCR do not establish certain amounts that the Companies will

> necessarily recover-thus, the Commission emphasizes that the $405 million figure discussed by NOPEC/NOAC and OSC is the maximum that could be collected under Rider DCR and is not a guaranteed amount. (Co. Ex. 1, Stip. at 20-23; Co. Ex. 3 at 14.)

And on pages 42-44, h. Commission Decision

> Page 43: Further, with respect to Rider DCR, the Commission encourages the Companies to consult with Staff to select projects, among others, which will mitigate effects of the transmission constraint in the ATSI zone of PJM (Co. Ex. 1, Stip. at 19-20). There is an ample record in this proceeding that the transmission constraint has resulted in a higher charge for capacity in the ATSI zone than PJM as a whole. Moreover, the record demonstrates that there are projects which can be undertaken by the Companies to mitigate, at the distribution level, the transmission constraint, in order to reduce capacity charges resulting from future base residual auctions (Tr. I at 335-336; Staff Ex. 1; Tr. II at 240-242). The Stipulation also adopts the terms and conditions of the Combined Stipulation regarding distribution rate design, as clarified by the Commission in the ESP 2 Case.
>
> Page 43-44: The Commission also notes that the auditor for Rider DCR is to be selected by the Staff with the consent of the Companies (Co. Ex. 1, Stip. at 22). Although the Commission is confident that the Companies would not unreasonably withhold consent, the Commission uses independent, outside auditors for a number of functions, and the Commission generally does not obtain the consent of the utility. Although this case does include unique circumstances, the Commission does not find that such circumstances justify this departure from general Commission practice. Accordingly, we will eliminate the provisions of the Stipulation requiring the consent of the Companies in the selection of the auditor for Rider DCR.
>
> The Commission notes that the Stipulation provides that the riders listed on Attachment B of the Stipulation shall be subject to ongoing Staff review and audit. According to the terms of the Combined Stipulation and past practice, separate dockets have been opened for the review of Riders DCR, AMI, and AER. The Commission clarifies that the Companies annually should file applications in separate dockets for the review and audit of Riders DCR, AMI, AER, NMB, and DSE. In addition, the Companies annually should file an application for the combined review of Riders PUR, DUN, NDU, EDR, GCR, and GEN. The Commission directs the Companies and Staff to develop a schedule for the filing of the annual reviews and audits. For all other riders on Attachment B, the Companies should continue to docket the adjusted tariff sheets; however, these tariff sheets should be filed in a separate docket rather than this proceeding, as has been the practice in the ESP 2 Case. Further, all filings adjusting riders listed on Attachment B should include the appropriate work papers.
>
> With this clarification, the Commission finds that the Stipulation as modified benefits ratepayers and the public interest, in accordance with the second prong of our test for the consideration of stipulations.

Order Page 44: 3. Does the settlement package violate any important regulatory principle or practice?

Staff further claims that the Stipulation affirmatively supports the state policies enumerated in Section 4928.02, Revised Code. Staff contends that the Stipulation supports competition by avoiding standby charges and other limitations consistent with Ohio policy. Section 4928.02(8), (C), Revised Code. It supports reliability though the continuation of the DCR mechanism consistent with Ohio policy. Section 4928.02(A), Revised Code. Staff claims that the Stipulation supports energy efficiency efforts through the support of energy coordinators, Section 4928.02(M), Revised Code, and supports at risk populations, Section 4928.02(L), Revised Code. Finally, Staff contends that economic development measures support Ohio's effectiveness in the global economy consistent with state policy. Section 4928.02(N), Revised Code.

And on page 48, c. Deferred Carrying Charges

The Commission notes that, under the terms of the proposed Stipulation, charges billed though Rider DCR will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. However, the Stipulation specifically excludes deferred carrying charges from the SEET calculation (Co. Ex. 1, Stip. at 23). We find that the provision of the Stipulation that provides for the exclusion of deferred carrying charges from the SEET does not violate an important regulatory principle or practice. Although the AEP-Ohio SEET Case stands for the principle that deferrals, including deferred carrying charges, generally should not be excluded from the SEET, Section 4928.143(F), Revised Code, specifically requires that consideration "be given to the capital requirements of future committed investments in this state." Rider DCR will recover investments in distribution, subtransmission, and general and intangible plant. Therefore, the Commission finds that, in order to give full effect to this statutory requirement, we may exclude deferred carrying charges from the SEET where, as in the instant proceeding, such deferred carrying charges are related to capital investments in this state and where the Commission has determined that such deferrals benefit ratepayers and the public interest. Accordingly, we find that the Stipulation provision excluding deferred carrying charges from the SEET does not violate an important regulatory principle or practice.

Order page 48, 4. Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code?

a. Summary of Parties' Arguments

Page 49: FirstEnergy first contends that the quantitative benefits of the ESP 3 are more favorable than an MRO. FirstEnergy specifies that, in its ESP v. MRO analysis, it considered the following quantitative provisions of the ESP: (1) estimated Rider DCR revenues from June 1, 2014, through May 31, 2016; (2) estimated PIPP generation revenues for the period of the ESP 3, reflecting the six percent discount provided by the Companies; (3) economic development funds and fuel fund commitments that the Companies' shareholders will contribute; and (4) estimated RTEP costs that will not be recovered from customers (Co. Ex. 3 at 17-19). Further, FirstEnergy states that it considered the following quantitative provisions of the MRO: (1) estimated revenue from base distribution rate increases based on the proposed Rider DCR revenue caps; and (2) generation revenue from PIPP customers excluding the six percent discount provided by the Companies. After comparing these quantitative factors, the

Companies calculate that the quantitative benefits of the ESP 3 exceed the quantitative benefits of an MRO by $200 million. (Co. Ex. 3 at 17-19.)

In its discussion of the quantitative benefits of the ESP 3, FirstEnergy acknowledges that Staff witness Fortney provided a different perspective of the ESP v. MRO analysis. In particular, the Companies note that Staff witness Fortney testified that the costs to customers of Rider DCR, which are included in FirstEnergy witness Ridmann's ESP analysis, and the costs of a distribution case, which are included in FirstEnergy witness Ridmann's MRO analysis, could be considered as a "wash" (Staff Ex. 3 at 4-5). Consequently, the Companies point out that Staff witness Fortney concluded that, even if foregoing RTEP cost recovery was eliminated as a benefit of the ESP 3, he would nevertheless consider the ESP 3 as benefiting customers relative to an MRO by over $21 million (Staff Ex. 3 at 5).

Page 50: As noted by the Companies, Staff also takes the position that an MRO is not preferable to the ESP 3 in this proceeding. In its ESP v. MRO analysis, Staff states that there are two ways to view the situation. Under the first view, Staff argues that one should remove the effect of the agreement to forego collection of RTEP costs from the analysis because this benefit was agreed to and provided in the ESP 2 and brings no new value to the ESP 3. Under this interpretation, Staff finds that the difference in cost between the ESP and MRO is less than $8 million. Staff contends that this is a sufficiently small difference in costs that the flexibility provided by the proposed ESP 3 makes it superior to an MRO. Further, Staff notes that the qualitative benefits of the ESP 3 further counterbalance the nominal difference in cost. Under the second view, Staff argues that the costs of Rider DCR under the ESP 3 and the effects of a rate case under an MRO are essentially a "wash," and that FirstEnergy witness Ridmann's analysis should be adjusted to remove the Rider DCR costs from the ESP 3 and the rate case expense from the MRO, respectively. Under this view, Staff argues that the ESP 3 is the more advantageous option by $21 million, even disregarding qualitative factors. (Staff Ex. 3 at 2-5.)

Page 50-51: In contrast, OCC/CP contend that the ESP 3 is not more favorable in the aggregate than an MRO under a quantitative or qualitative analysis. Regarding the Companies' quantitative analysis, OCC/CP contend that the alleged RTEP benefit was improperly double-counted by the Companies and should be excluded from the analysis. Specifically, OCC/CP argue that the RTEP cost recovery forgiveness amount would remain the Companies' obligation under the ESP 2 and is not contingent upon the Commission's approval of the ESP 3 (Joint NOPEC/NOAC Ex. 1 at 5). Next, OCC/CP argue that Rider DCR cannot be considered a "wash" with a distribution rate case outcome. More specifically, OCC/CP contend that Rider DCR is more costly to customers because, according to FirstEnergy witness Ridmann, $29 million net cost is attributed to Rider DCR due to lag in distribution cost recovery (Co. Ex. 3 at 18). OCC/CP next argue that the PES offer of a six percent discount to PIPP customers should not be considered a benefit of the ESP 3, because it would not be a prohibited arrangement in an MRO (OCC Ex. 11 at 30-31). Further, OCC/CP point out that the Companies did not solicit bids from other suppliers besides PES to determine if there was interest in serving the PIPP load at an even greater discount. Next, OCC/CP contend that the alleged public benefits of the fuel funds ignore the benefit derived by FirstEnergy. OCC/CP explain that the $9 million in fuel fund monies is used for the payment of electric bills and, consequently, argue that this represents a benefit to the Companies because it ensures revenues. Finally, OCC/CP argue that the costs associated with the economic development provisions of the Stipulation are merely "transfers" of payments and should not be considered a benefit of the ESP 3. OCC/CP specify that the economic development provisions contain dollar amounts and non-bypassable discounts given to certain entities, which are ultimately recovered from other customers (OCC Ex. 11 at 33).

Page 51-52: Similar to OCC/CP's arguments, NOPEC/NOAC contend that FirstEnergy has failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically,· NOPEC/NOAC argue that FirstEnergy's analysis wrongly seeks to double-count the RTEP cost recovery forgiveness benefits for purposes of the ESP v. MRO test, although that obligation was incurred as part of the ESP 2 (NOPEC/NOAC Joint Ex. 1 at 5). NOPEC/NOAC argue that, when this quantitative benefit is removed, the ESP 3 value becomes $7 million less favorable than an MRO (Id. at 6). Additionally, NOPEC/NOAC argue that FirstEnergy improperly included in its analysis an assumed Commission-approved distribution rate increase of $376 million under an MRO in order to offset the $405 million to be collected from Rider DCR under the ESP 3 (Co. Ex. 3, Att. WRR-1). NOPEC/NOAC contend that the $376 million assumption is unrealistic and speculative, given that FirstEnergy was only awarded a distribution rate increase of $137.6 million in 2007. NOPEC/NOAC argue that a more accurate estimate of a distribution rate increase would make the proposed ESP 3 less favorable than the MRO by several hundred million dollars.

Page 52: NOPEC/NOAC next contend that, if the Commission desires to adopt an ESP over an MRO, the Commission should also adopt NOPEC/NOAC's recommendations so that the ESP 3 proposal can satisfy the ESP v. MRO test. NOPEC/NOAC recommend that the Commission include the following modifications to the proposed ESP 3 (1) elimination of the continuation of Rider DCR after May 31,2014, and replacement with a separately filed distribution rate case; (2) elimination of FirstEnergy' s proposal to exclude income it receives from deferred charges from the SEET calculation; (3) requirement that the Companies bid all of their eligible demand response and energy efficiency resources into all future PJM capacity auctions; and (4) holding of the proposed energy auctions in October 2012 and January 2013 in accordance with the terms of the Combined Stipulation.

OSC similarly contends that, when the Companies' proposal is viewed in light of the evidence presented in this case, the Companies have failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically, OSC claims that the evidence presented at hearing shows that, quantitatively, the ESP 3 proposal will cost consumers more than the expected results of an MRO because the ESP 3 proposal will allow FirstEnergy to continue Rider DCR after May 31, 2014, to recover up to $405 million in distribution improvement expenditures. (Tr. I at 129.)

AEP Retail also contends that the Companies' proposed ESP 3 fails the ESP v. MRO test quantitatively. Specifically, AEP Retail contends that the $293.7 million in RTEP costs should not be included in the analysis because this benefit was a result of the Commission's decision in the ESP 2 Case and would not be a benefit of the ESP 3 (Staff Ex. 3 at 2). AEP Retail also argues that the claimed qualitative benefits are suspect because the Companies were unable to secure any benefit by bidding demand response resources into the 2015-2016 base residual auction, because the benefits of a six percent PIPP discount are unknown and violate Section 4928.02, Revised Code, because the extension of the recovery period for REC costs is not a benefit, because the distribution "stay out" period and Rider DCR are an illusory benefit, and because any benefit of the three-year blending proposal is impossible to assess. (Tr. IV at 23; OCC Ex. 9 at 8-9; OCC Ex. 11 at 32; Tr. I at 250-257.)

Page 53: Regarding Rider DCR, the Companies reply to other parties' arguments that the recovery of any dollars in a rate case is speculative, especially when compared to the amounts that the Companies recovered in their last distribution rate case. The Companies contend that, if they are able to make a proper showing to obtain recovery of distribution infrastructure costs under Rider DCR, there is no reason to believe that they would be unable to make a similar showing to obtain recovery in a rate case. Further, the Companies argue, in response to OCC/CP, NOPEC/NOAC, and OSC's arguments that recovery could be up to $405 million, that the caps established in Rider DCR are just caps-and that there is no guarantee to what the Companies may recover under Rider DCR.

Page 53-54: Next, the Companies rebut OCC/CP and AEP Retail's arguments that the Companies' agreement not to seek a base distribution rate increase is not a benefit. The Companies point out that a rate case would involve the recovery of costs beyond those permitted to be recovered under Rider DCR. Further, the Companies point out that the Commission has already held that a base distribution rate freeze provides a benefit that makes an ESP more favorable in the aggregate than an MRO in the ESP 2 Case. Finally, the Companies note that they cannot recover any monies unless they can show that the plant is in service, and that Rider OCR is subject to quarterly reconciliations and an annual audit. ESP 2 Case, Opinion and Order (Aug. 25, 2010) at 44.

Page 54: In its reply, Staff reiterates that the Companies have met their criteria regarding Rider DCR. Staff contends that it examined the reliability of the Companies' system and found that the Companies were in compliance with the applicable standards (Staff Ex. 2 at 5-6). Staff states that compliance with the standards means that customers are getting the level of reliability that they want.

In their reply brief, OCC/CP respond that the Companies are unrealistic in assuming that, if they collected $405 million through Rider DCR, they would likely recover that same amount of costs through a distribution rate case. OCC/CP point out that, in the last distribution rate case, the Companies requested $340 million, but that the Commission reduced the amount to $137 million in annual rate increases. Distribution Rate Case, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48. Further, OCC/CP contend that they are not advocating for a decrease in service quality, but do not want the Companies to" gold plate" their distribution systems.

Page 55, b. Commission Decision

Page 56: The Commission also notes that the proposed ESP 3 is consistent with policy guidelines in Ohio. Specifically, the proposed ESP 3 supports competition and aggregation by avoiding standby charges, supports reliable service through the continuation of the DCR mechanism, supports business owners' energy efficiency efforts, protects at-risk populations, and supports industry in order to support Ohio's effectiveness in the global economy (Co. Ex. 3 at 11-12).

Dissenting Opinion of Commissioner Cheryl L. Roberto

Page 4-5: D. Continuation of Rider DCR: utility and customer expectations are not aligned; without alignment utility gains additional revenues without produces additional customer value

Rider DCR is proposed pursuant to Section 4928.143(B)(2)(h), Revised Code, which authorizes an ESP to include:

> Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking . . . provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include ... any plan providing for the utility's recovery of costs ... a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

In order for Rider DCR to be included appropriately within the ESP 3, the Companies have the burden to demonstrate that the Companies' and customers' expectations are aligned and the Companies are dedicating sufficient resources to reliability. Additionally, this provision must be judged as part of the aggregate terms and conditions of an ESP; e.g. if a similar or better result is achievable through an MRO, then it calls into question whether the ESP is beneficial.

The Sierra Club notes that despite ample notice of the 2015/2016 RPM auction and the likely consequences for the Companies' customers, the Companies failed to take any steps to prepare for the RPM auction. These actions could have included bidding in energy efficiency and demand response. Accordingly, the Sierra Club argues that the Companies should be held accountable for the financial harm caused to its customers. I agree with the majority that this proceeding was not opened to investigate the Companies' bidding behavior. It is not a complaint case. The majority notes that "the record does not support a finding that the Companies' actions in preparation for bidding into the 2015/2016 base residual auction were unreasonable." If this were a complaint case, a standard of reasonableness would be appropriate. See Section 4905.26, Revised Code. In this instance, however, the burden is upon the Companies to demonstrate that its actions are aligned with both its own interests and those of its customers and that it is dedicating sufficient resources to reliability. The Companies may only avail themselves of the benefits of single-issue rate-making pursuant to Section 4928.143, Revised Code, after they have successfully made this demonstration. The information in our record is insufficient to find that the Companies dedicated sufficient resources to reliability, particularly in the form of participation in the base residual auctions whose very purpose is reliability. For this reason, I find that continuation of Rider DCR is not supported by this record.

Finally, the Companies have a remedy for cost recovery for prudent distribution system investments in form of a distribution rate case. If the Companies require additional resources, they may file requests under traditional ratemaking processes.

Case No. 14-1297-EL-SSO Commission Opinion and Order

Order, page 25, (11) Third Supplemental of the Stipulation:

> The revenue caps for the Delivery Capital Recovery Rider (Rider DCR)[228] will increase annually to $30 million for the period of June 1, 2016, through May 31, 2019; $20 million for the period of June 1, 2019, through May 31, 2022; and $15 million for the period of June 1, 2022, through May 31, 2024. Further, the audit schedule set forth in the Application shall be amended to provide audits for the entire term of the Stipulated ESP IV, and the amended language shall read: "The independent auditor shall be selected by Staff. The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable and will be conducted following the Companies' December 31 filing during the term of the Companies' ESP IV, and one final audit following the Companies' final June 30 reconciliation filing." (Co. Ex. 154 at 13.)

Order, page 29, (32) Third Supplemental of the Stipulation:

> The Signatory Parties agree that the following termination and transition of the Stipulated ESP IV must occur under the fourth-year test required by RC 4928.143(E): (1) the Commission's test of the plan, including the impact of termination on the financial health of the utilities; and (2) a finding that the results of the test conclude that the remainder of the Stipulated ESP IV is no longer more favorable than an MRO and that the remainder of the ESP IV is likely to result in significantly excessive earnings for each utility. However, termination shall not affect continued cost recovery of Riders DCR and RRS. (Co. Ex. 154 at 18.)

Order, page 65-66, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (e) Delivery Capital Recovery Rider

[228] Rider DCR allows the Companies to earn a return of and on plant-in-service associated with distribution, transmission, general, and intangible plant, which was not included in the rate base from the Companies' last distribution rate case.

FirstEnergy also argues that Stipulated ESP IV benefits customers and the public interest by helping to ensure reasonably priced and reliable distribution service. Initially, FirstEnergy contends that continuing the distribution rate freeze will also benefit customers (Co. Ex. 155 at 3). In connection with the freeze, FirstEnergy states the continued recovery of lost distribution revenue will appropriately balance the interests of customers with the interests of the Companies' shareholders (Co. Ex. 7 at 8). Further, the Companies stress that they will be required to show total investment amounts and provide justification as to why it is appropriate to recover these investments through Rider DCR, which will then be subject to an annual audit. As Rider DCR provides the Companies with the opportunity to invest in infrastructure in a more proactive manner, FirstEnergy asserts that the Companies have consistently outperformed their system average interruption frequency index (SAIFI)[229] and customer average interruption duration index (CAIDI)[230] minimum reliability standards since Rider DCR has been in effect (Co. Ex. 50 at 9). Additionally, the Companies propose to increase the annual cap for revenue recovered under Rider DCR from $15 million per year to $30 million for the first three years, with a $20 million increase annually for the subsequent three years and $15 million annually for the final two years of the proposed eight-year term (Tr. Vol. XX at 3961-64). During the evidentiary hearing, FirstEnergy alleged that no intervening witnesses could contest that actual revenue requirements have increased $30 million annually on average (Tr. Vol. XXI at 4117-19; Tr. Vol. XXXVIII at 8231).

While OCC/NOAC initially contends that Rider DCR will not result in a financial "wash" under the MRO v. ESP test, as proffered by FirstEnergy witness Fanelli, OCC/NOAC, NOPEC, and RESA argue the alleged qualitative benefits arising from Rider DCR will not actually accrue to customers and, instead, will cause customers to pay more than they otherwise would be required to pay under a distribution rate case (Co. Ex. 50 at 7; OCC Ex. 18 at 17; OCC/NOPEC Ex. 8 at 30; OCC/NOPEC Ex. 11 at 22-23). OCC/NOAC, NOPEC, and RESA argue these revenue cap increases could ultimately result in customers paying an additional $240 to $330 million in revenues, for a total of $915 million in Rider DCR charges over the term of Stipulated ESP IV (OCC/NOPEC Ex. 11 at 23-24). Additionally, OMAEG and NOPEC maintain the Companies have provided no evidence showing the need for this increased cap, especially since no major distribution capital projects are currently planned (Co. Ex. 50 at 4; Staff Ex. 6 at 7-9; OCC Ex. 18 at 19). OCC/NOAC, Power4Schools, and OMAEG further assert that Rider DCR will function more efficiently or foster greater reliability when collecting these costs through a base distribution rate case (OCC/NOPEC Ex. 8 at 31). OMAEG, NOPEC, and Power4Schools assert it would not be reasonable or prudent for the Commission to allow the Companies to incrementally increase the distribution rate, absent a thorough Commission review of such rates in a distribution rate case, noting it has already been seven years since the Companies' last distribution rate case (OCC Ex. 22 at 3; Tr. Vol. XX at 3901). Moreover, OMAEG and NOPEC add that, in the event the Companies are earning returns that exceed their

[229] Represents the average number of interruptions per customers.
[230] Represents the average interruption duration.

> actual costs of capital, additional Rider DCR increases are both unnecessary and inappropriate (OCC Ex. 18 at 11). OCC/NOAC further asserts that allowing Rider DCR to continue to be charged to customers in the event the ESP is terminated pursuant to R.C. 4928.143(E) would be harmful, due to the fact, in their opinion. Rider DCR contributes to the failure of the MRO v. ESP test.

Order, page 66-67, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (f) Government Directives Recovery Rider

> FirstEnergy believes that the Government Directives Recovery Rider (Rider GDR) proposed in its application will permit timely recovery of future costs related to implementing programs required by legislative or governmental directives over which the Companies would have no control (Tr. Vol. I at 180; Co. Ex. 16 at 4). Given the proposed eight-year term of Stipulated ESP IV, FirstEnergy argues that it is appropriate to establish a cost-recovery mechanism now for possible future charges incurred because of governmental actions or directives in order to ensure the recovery oi such costs is completed in a uniform and consistent manner subject to Commission review and approval. (Tr. Vol. XXIV at 4905; Co. Ex. 16 at 3). As a part of Stipulated ESP IV, the Companies are specifically requesting deferral authority and recovery of the costs associated with the supplier web portal and bill logos through Rider GDR. Additionally, the Companies note that no costs related to proposed Rider GDR had been incurred at the time of the evidentiary hearing. (Co. Ex. 15 at 7-8; Tr. Vol. V. at 1030-33,1079-83,1101.)
>
> Similar to its objections to Rider DCR, OCC/NOAC, Power4Schools, and NOPEC argue the alleged benefits resulting from Rider GDR are without merit, noting that this is again an attempt by the Companies to request approval of an asymmetric, single-issue ratemaking request when substantial excess earnings are already being recovered by the Companies. OCC/NOAC additionally contend that the proposed Rider GDR provides no incentive or requirement for Companies to file for rate reductions resulting from changes hi governmental regulations. (OCC/NOPEC Ex. 7 at 32.) OMAEG also adds that FirstEnergy witness Mikkelsen even testified that it is too early to ascertain the types of costs that will result from implementing these directives or to estimate the amount of costs to be recovered under the rider from customers (Co. Ex. 7 at 25).

Order, page 69-70, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (i) Grid Modernization Program

> FirstEnergy alleges that the Stipulated ESP IV will also benefit customers through its grid modernization provision, as this provision contains several initiatives that would further promote customer choice in the Companies' service territories, including, but not limited to. Advanced Metering Infrastructure (AMI), DACR, Volt/VAR, engaging Staff to attempt to remove any barriers for distributed generation, consulting with Staff regarding net-metering tariffs, and full deployment of advanced smart meters (Co. Ex. 154 at 9-10). The Companies believe implementation of such initiatives will ultimately lead to customer savings and promote retail competition in the state of Ohio (Co. Ex. 154 at 3). Additionally, FirstEnergy states that the Companies will file a

grid modernization plan with the Commission within 90 days of the filing of Stipulated ESP IV, in which all interested parties would have the opportunity to participate (Co. Ex. 154 at 9-10; Co. Ex. 155 at 4; Tr. Vol. XXXVI at 7584-85, 7624). The Companies state that costs associated with any approved grid modernization project would be recovered through Rider AMI, commencing within three months after Commission approval of the project and would be calculated based on a forward-looking formula rate (Co. Ex. 154 at 9-10). Further, FirstEnergy provides that the ROE would be initially set at 10.88 percent based on the currently approved ROE for ATSI plus a 50 basis point incentive mechanism to incentivize grid modernization investment over other potential types of investment (Co. Ex. 154 at 10; Tr. Vol. XXXVI at 7631-32; Tr. Vol. XXXVII at 7775).

Environmental Groups and OCC/NOAC allege that the Stipulated ESP IV may actually harm customers, noting the preclusion to terminate Rider RRS and Rider DCR before 2024 and arguing the Companies' commitment to file a grid modernization plan does not warrant the Commission approving an incentive ROE on grid modernization investments absent any evidence showing that it will not provide windfall profits to the Companies (ELPC Ex. 28 at 13-14). OCC/NOAC further asserts that the proposed ROE is unjust and unreasonable, as it is higher than the current ROE approved for FirstEnergy's SmartGrid pilot (Tr. Vol. XXXVII at 777^-7775). OCC/NOAC and OHA also contend that it would be unwise for the Commission to agree to an upfront fixed ROE for facility deployment regarding DACR and Volt/VAR technologies before any details of the grid modernization plan are known.

Order, page 75, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (m) Low-Income Customer Assistance Programs and Initiatives

As discussed earlier, FirstEnergy and Citizens Coalition maintain that Stipulated ESP IV will benefit customers and the public interest by supporting low-income customers. Apart from all customers enjoying reliable power at market-based prices, FirstEnergy has corrupted to provide funding for several programs geared toward assisting low-income customers, including the Community Corrections program, the Cleveland Housing Network, the Council for Economic Opportunities in Greater Cleveland, the Consumer Protection Association for a Fuel Fund Program, OPAE, and the Customer Advisory Agency. (Co. Ex. 7 at 30; Tr. Vol, I at 44, 65, 200-201, 205; Tr. Vol. II at 427; Co. Ex. 154 at 17; Co. Ex. 155 at 11.) Citizens Coalition also emphasizes the importance of and demonstrable need for maintaining these various low-income programs, adding that the funding provided as a part of Stipulated ESP IV will help promote involvement in these programs.

OCC/NOAC state that, contrary to FirstEnergy's assertions, low-income customers will be significantly impacted by Stipulated ESP IV, as it is does not continue certain low-income assistance programs and will significantly increase costs charged to these customers through Rider RRS, Rider DCR, and Rider GDR. Moreover, OCC/NOAC believe that, due to the exorbitant costs to low-income customers, the amount of customers whose electric service is terminated for non-payment may increase as a result oi approving Stipulated ESP IV. Further, NOPEC points out that while many low-

> income groups will be receiving payouts funded by shareholders, the Stipulated ESP IV does little to benefit the Companies' ratepayers, who NOPEC asserts are captive and will be required to pay the eventual cost of Rider RRS. (OCC/NOPEC Ex. 9 at 7,12; OCC Ex. 27 at 7-9,13-14,16,19,22.)

Order, page 92-93, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (m) Commission Decision/ (iv) Additional Benefits of Stipulation

> The key provisions in the Stipulations related to distribution rates is the continuation of rate base distribution rate freeze for eight years under ESP IV. The extension of the distribution rate freeze will promote stable rates, as base distribution rates will not rise during the term of ESP IV (Co. Ex. 155 at 3). The Commission notes that base distribution rates have not increased in the Companies' service territories since 2009. In re FirstEnergy, Case No. 07-551-EL-AIR et. al., Opinion and Order (Jan. 29, 2009). However, in light of the proposed distribution rate freeze, it is necessary and appropriate to continue the existing Rider DCR mechanism, which allows the Companies to recover reasonable investments in plant in service associated with distribution, subtransmission, and general and intangible plant, which was not included in the rate base oi the Companies' last distribution rate case. We note that Rider DCR was first approved by the Commission in FirstEnergy's ESP II and has been in effect since January 1, 2012. ESP II Case, Opinion and Order at 11. The Stipulations provide for continued annual audits of recovery under Rider DCR and requires the Companies to demonstrate what they spent and why the recovery sought is not unreasonable. These distribution investments are necessary to maintain distribution reliability at current levels. Likewise, the storm cost deferral mechanism facilitates the distribution rate freeze by allowing the Companies to defer unusually high storm damage expenses in the event such expenses are actually incurred.

Order, page 105-106, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (c) Other Provisions

> Regarding Rider DCR, OCC/NOAC and Power4Schools oppose its proposed continuation and the continuation of the base distribution rate freeze, arguing that this proposal avoids the scrutiny of a base distribution rate case in violation of prudent regulatory policy (Co. Ex. 154 at 13).

Order, page 107, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (c) Other Provisions

> Next, FirstEnergy responds to parties' arguments regarding the lawfulness of Riders DCR and GDR. FirstEnergy asserts that R.C. 4928.143(B)(2)(h) expressly permits single issue ratemaking as part oi an ESP. Additionally, FirstEnergy points out that the Commission previously approved Rider DCR as part of an ESP. ESP II Case; ESP III Case. FirstEnergy also addresses the Environmental Groups' argument that the Companies should not be permitted to receive lost-distribution revenue tied to the Customer Action Program under Commission precedent. FirstEnergy argues that this provision is an integral part of the Stipulated ESP IV that is supported by all signatory parties, and that tae Customer Action Program is an energy efficiency program authorized by R.C. 4928.662 and is contained in the Companies' Commission-

approved EE/PDR Portfolio Plan. In re FirstEnergy, Case No. 12-2190-EL-POR, Finding and Order (Nov. 20, 2014) at 8-9. Next, FirstEnergy addresses parties' objections to the federal advocacy provision, arguing that this provision does not violate state policy and the Commission is well within its powers to accept the recommendation if it believes it is reasonable. Finally, FirstEnergy asserts that the proposed HLF/TOU pilot program is not unduly discriminatory and unjust as alleged by some parties, arguing that eligibility requirements in order to create a homogenous pool are necessary for such a pilot program (Tr. Vol. II at 290-291, 463-467; Co. Ex. 146 at 17).

Order, page 111, E Consideration of Stipulated ESP IV/ 4- ESP versus MRO Test

With respect to Rider DCR, the Commission is not persuaded by claims by OCC/NOAC and others that costs under Rider DCR fail to receive proper scrutiny. As we have stated previously, Rider DCR is subjected to annual audits which require the Companies to demonstrate what they spent and why the recovery sought is unreasonable. ESP III Case, Opinion and Order at 34. The Commission has been conducting such audits annually since the inception of Rider DCR. Thus, OCC/NOAC and any other party have had, and will continue to have, a full and fair opportunity to raise any issues regarding distribution investments to be recovered under Rider DCR during the audit process.

Order, page 113-114, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (i) Appropriate Application of the MRO v. ESP Test

NOPEC initially argues that the General Assembly intended, and the Ohio Supreme Court later confirmed, that the Commission is limited to only consider the quantitative factors listed in R.C. 4928.143(B) in its analysis of a proposed ESP, and thus, the language within R.C. 928.143(C)(1) must be construed consistent with that intent. R.C. 1.49; In re Columbus S. Power Co., et al, 128 Ohio St.3d 402, 2011-Ohio-958. Thus, NOPEC states that while a variety of qualitative benefits have been forwarded by the Companies in support of Stipulated ESP IV for purposes of prong two of the three-prong test, these qualitative benefits may not be considered for purposes of the ESP v. MRO test. Accordingly, NOPEC and OCC/NOAC provide that the Commission's determination of whether the proposed Stipulated ESP IV is more favorable in the aggregate than the MRO rests on a determination of whether the identifiable costs of the ESP are greater than the cost of an MRO. Additionally, as only the items listed in R.C. 4928.143(B) may be included for the Commission's consideration of an ESP, NOPEC also argues that the implementation of Rider GDR should be disallowed since no foreseeable costs to be recovered through this rider have been presented (OCC Ex. 18 at 23). NOPEC also disagrees with the Companies' decision to omit the costs associated with Rider DCR as part of the ESP v. MRO test, noting that OCC/NOPEC witness Kahal demonstrated that the revenues associated with Rider DCR were a quantifiable cost of the ESP and that they should be considered since the "expected results" of R.C. 4928.142 do not contemplate consideration of rate results of a distribution rate case. Power4Schools also contends that only quantitative benefits should be considered, and thus, the Commission should find the ESP to be less favorable than an MRO. P3/EPSA and RESA assert that the Companies have failed to meet their burden to show that the ESP would be more beneficial than an MRO, stating Stipulated ESP IV does not contain an explicit evaluation of this test, and instead, relies on conclusory arguments that this is the case. (Co. Ex. 154 at 18; Co. Ex. 155 at 10-14.)

Order, page 114-116, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (ii) Quantitative Benefits and Analysis

FirstEnergy claims that the ESP is estimated to be more favorable than the expected results of the MRO by $612.1[231] on a normal basis, or $260 million on a NPV basis (Co. Ex. 155 at 12; Co. Ex. 156 at 4-6). More specifically, and as discussed above, the Companies assert that this quantitative benefit is a combination of the Economic Stability Program as well as economic development and low-income funding. The Companies elected to omit the costs of Rider DCR m this analysis, posited on the fact that the Companies would utilize a CBP to procure generation under either Stipulated ESP IV or an MRO; thus, there would be no quantifiable difference relating to this pricing between either the two scenarios. Additionally, FirstEnergy reiterates its earlier arguments regarding the quantitative benefits associated with Stipulated ESP IV.

OCC/NOAC argue that the Companies' proposed Stipulated ESP IV is quantitatively more costly to customers than an MRO over its eight-year term, noting that the combined analyses of OCC/NOPEC witnesses Wilson and Kahal demonstrated that the actual cost of the ESP over that of an MRO would range from $3.26 to $3.35 billion (OCC/NOPEC Ex. 11 at 16, 26-27; OCC/NOPEC Ex. 7 at 8). Exelon, RESA, NOPEC, and OMAEG also provide that the only number that should be considered for purposes of this test is the Companies' projected credit arising under Rider RRS, since there is no indication that rate other payments to be paid under Stipulated ESP IV could not otherwise be made under an MRO (Tr. Vol. XIII at 596). While OCC/NOAC initially contends that Rider DCR will not result in a financial "wash," as proffered by FirstEnergy witness Fanelli, OCC/NOAC, NOPEC, and RESA argue the alleged qualitative benefits arising from Rider DCR will not actually accrue to customers and, instead, will cause customers to pay more than they otherwise would be required to pay under a distribution rate case (Co. Ex. 50 at 7; OCC Ex. 18 at 17; OCC/NOPEC Ex. 8 at 30; OCC/NOPEC Ex. 11 at 22-23). Additionally, Exelon states the evidence in the record shows the speculative nature of this projection, while also noting that the Companies failed to conduct, or even consider, a CBP in order to ensure customers pay the least amount for the purported benefits under Rider RRS (Tr. Vol. XXXVl at 7736; Exelon Ex. 4 at 3; Exelon Ex. 1 at 20.) Environmental Groups also state that the Commission lacks any reassurances, such as a competitive procurement or some objective benchmark price, which would allow it to adequately evaluate whether the PPA is just and reasonable or more favorable in the aggregate than an MRO. Based on

[231] The Companies derive this number by adding their projected net benefit attributed to Rider RRS, $561 million, and the additional $51.1 million in quantitative benefits in the form of shareholder funding for economic development, low-income customers, and a customer advisory agency.

> OCC/NOPEC witness Kahal's analysis, and further supported by Exelon's offer, NOPEC also contends that Rider RRS should be quantified as costing ratepayers $2.97 billion (OCC/NOPEC Ex. 11 at 18). OMAEG notes that while the Companies made changes to its claimed quantitative analysis to account for the shortened eight-year term of Rider RRS and updated ROE of 10.38 percent, they failed to update their energy, capacity, natural gas, and CO2 price forecasts, which were more than 17 months old (Tr. Vol. XXXVI at 7513). OMAEG argues this outdated information cannot be considered reasonable by rate Commission, especially when other parties in this proceeding have provided more recently updated forecasts that allude to an entirely different outlook for consumers (Tr. Vol. XXXVIII at 8118-19; OCC/NOPEC Ex. 9 at 12-13). Additionally, OMAEG asserts that the Companies failed to provide any costs associated with the riders and programs contained in the Third Supplemental Stipulation in their bill impact analyses, even though these provisions may result in significant additional costs to customers who are not eligible for such programs or do not receive the specific benefits (Co. Ex. 154 at 9-15).
>
> Next, FirstEnergy responds to parties' arguments regarding whether Rider DCR should be included in calculation of the quantitative impact. FirstEnergy maintains that Rider DCR does not have a quantitative impact on the ESP v. MRO test, as Commission precedent considers recovery of distribution capital costs through Rider DCR to be equivalent to the recovery of similar costs through a distribution rate case. ESP III Case Order at 56. Further, FirstEnergy responds to parties' arguments that low-income funding commitments should not be counted as a quantitative benefit because similar commitments could be made by the Companies under an MRO. FirstEnergy urges the Commission to reject these arguments on the grounds that whether the Companies theoretically could make such funding commitments under an MRO is irrelevant, as FirstEnergy witness Mikkelsen explained these funding commitments are specifically being made as part of the proposed ESP and would not exist otherwise (Tr. Vol. XXXVI at 77^5-77^6). Additionally, FirstEnergy points out that there is no Commission precedent showing that any such commitments could be required as part of a distribution rate case.

Order, page 116-117, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (iii) Qualitative Benefits and Analysis

> The Companies further assert that Stipulated ESP IV includes a variety of qualitative benefits, which promote rate stability, economic development, retail competition, customer optionality, grid modernization, resource diversification, low-income customer assistance, continued investment in the delivery system, and system reliability. The Companies have concluded that these benefits would not be available under an MRO. (Co. Ex. 155 at 13, Co. Ex. Co. Ex. 8 at 11; Co. Ex. 50 at 8-9.) As discussed earlier, the Companies state that several provisions previously approved in the ESP III Case will continue to be utilized in Stipulated ESP IV, including the continuation of the base distribution rate freeze, the procurement of non-shopping load through a CBP, the continuation of Riders DCR, ELR, and EDR(h), and the continued support of economic development and low-income programs through various funding

initiatives. Additionally, FirstEnergy reiterates its earlier arguments regarding the qualitative benefits evaluated above in the traditional three-prong test.

Though many parties have argued that qualitative benefits should not even be considered for purposes of the ESP v. MRO test, they also argue that in the event the Commission could or would consider them, they would be significantly outweighed by the quantifiable costs attributable to Stipulated ESP IV. P3/EPSA, Power4Schools, and RESA indicated taat there has been an overreliance on the qualitative benefits to shadow the fact that the quantitative benefits will likely not accrue to the Companies' customers (Tr. Vol. XXXVl 7736-37). NOPEC and Power4Schools also state that even if the Commission was statutorily authorized to consider qualitative factors during its evaluation of the MRO v. ESP test, it would be unlawful to consider qualitative factors that fall outside of the provisions oi R.C. 4928.143(B) and unreasonable for such qualitative benefits, such as benefits furthering the state policies codified in R.C 4928.02 or the benefits of proposed Riders DCR and GDR, to supersede the quantitative analysis required by R.C 4928.143(C)(1). Furthermore, OMAEG, OCC, NOAC, and Power4Schools assert tae Companies have failed to show that the qualitative benefits of Stipulated ESP IV are more favorable than an MRO, initially noting that the projected costs of Rider RRS during the eight-year term outweigh any claimed benefits, such as rate stability or reliable electric service (OCC/NOPEC Ex. 4 at 49-52; OCC/NOPEC Ex. 8 at 8). Specifically, OMAEG contends that the costs attributed to Rider RRS would greatly outweigh any incremental annual rate increase customers would experience otherwise, while adding that there would be no change in reliability if the Plants and OVEC entitlement units were to continue to operate as they do today but such a decision might have significant opportunity costs such as foregone new generation construction (OCC/NOPEC Ex. 9 at 12; Tr. Vol. XIII at 2797-99). In addition, OMAEG argues that the projected economic development benefits are flawed and the Companies' analysis fails to accurately reflect the impact of Rider RRS on the costs to customers and the resulting economic development in this region, noting that the Companies should not be able to claim these projected benefits if they cannot definitively state that the Plants and OVEC entitlement units are currently operating economically (Co. Ex. 141 at 6; OCC/NOPEC Ex. 11 at 20-21). OMAEG concludes by arguing that while the Companies assert the provisions contained in Stipulated ESP IV will provide additional qualitative benefits, these provisions will only benefit a handful of customers to the detriment of the majority. In addition, many parties reiterated their concerns regarding the various purported benefits in the second prong analysis of the traditional three-prong test.

Order, page 119, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (b) Commission Conclusion

With respect to whether Rider DCR should be included in the quantitative analysis, the Commission previously has determined that Rider DCR allows the Companies to earn a return on and of plant in service associated with distribution, subttansmission, and general and intangible plant which was not included in the rate base of the Companies' last distribution rate case. Pursuant to R.C 4909.15, the Commission is required to determine, in a distribution rate case, the valuation, as of the date certain, of property used and useful in rendering public utility service. Thus, we concluded that, to the extent that the Companies have made capital investments since the last distribution rate case, those investments will be recovered to an equal extent, through either Rider DCR or through distribution rates, provided that the property is used and useful in the provision of distribution service. Accordingly, over the long term, the Companies will recover the equivalent of the same costs, and, for purposes of the ESP v. MRO Test, the costs of Rider DCR and the costs of a potential distribution rate case should be considered substantially equal and removed from the ESP v. MRO analysis. ESP III Case, Opinion and Order (Jul. 18, 2013) at 55-56; Entry on Rehearing (Jan 30, 2013) at 22-23.

APPENDIX B: ABBREVIATIONS AND ACRONYMS

The following abbreviations and acronyms are used in this report.

ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used during Construction
AMI Rider	Advanced Metering Infrastructure (Smart Grid) Rider
ARO	Asset Retirement Obligation
ATSI	American Transmission Systems, Inc.
CAT	Commercial Activity Tax
CE, CEI, or CECO	Cleveland Electric Illuminating Company, The
CIAC	Contributions in Aid of Construction
CPR	Continuing Property Records
CREWS	Customer Request Work Scheduling System
CWIP	Construction Work in Progress
DCR	Delivery Capital Recovery Rider
DMP	Distribution Modernization Platform
DSI Rider	Delivery Service Improvement Rider
DTL	Deferred Tax Liability
EDR Rider	Economic Development Rider
ESP	Electric Security Plan
FE or FECO	FirstEnergy Service Company
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
IT	Information Technology
LEX Rider	Line Extension Recovery
LOSA	Level of Signature Authority
MRO	Market Rate Offer
OE or OECO	Ohio Edison Company
PUCO	Public Utilities Commission of Ohio
RFP	Request for Proposal
RWIP	Retirement Work in Progress
TE or TECO	Toledo Edison Company, The
TCJA	Tax Cuts and Jobs Act
SEET	Significantly Excessive Earnings Test
SSO	Standard Service Offer
WBS	Work Breakdown Structure

APPENDIX C: DATA REQUESTS AND INFORMATION PROVIDED

The following is a list of the data requests submitted by Blue Ridge to FirstEnergy. Responses were provided electronically and are available on a confidential CD.

Data Request Set 1 (Submitted January 9, 2019)

1.1. **Priority Data Request—DCR Filings**: For each company, please provide the workpapers and documents that support the information included within the December 31, 2018, Rider DCR Compliance Filing. Please provide the source data in its original electronic format.

1.2. **Priority Data Request—Workorders**: For each company and the Service Company, please provide in a Microsoft Excel spreadsheet a list of work orders by FERC account for 12/1/17 through 11/30/18. Include the description, dollar amount, completion date, and whether the work was an addition or replacement.

1.3. **Priority Data Request—Organization Charts**: For each company and the Service Company, please provide a current organizational chart.

1.4. **Priority Data Request—Organization Chart**: Please confirm that the following individuals were in the same positions for 2018. Please identify any changes.

#	Name	Title
1	Douglas Burnell	Director, Business Services
2	Amy Patterson	Manager, Property Accounting
3	Randal Coleman	Manager, Distribution Standards
4	Joanne Savage	Manager, OH Revenue Requirements
5	Sandra Hemberger	Director, Corporate Sourcing
6	Peter Nadel	Manager, Insurance and Operational Risk Management
7	Santino Fanelli	Director Rates & Regulatory Affairs
8	Brandon McMillen	OH State Regulatory Analyst III
9	John Nauer	Director, Utilities Sourcing
10	Albert Pompeo	FEU Business Services Policy and Control Lead
11	Nicholas Fernandez	Executive Director, Strategy and LT Planning
12	Mark Golden	Manager, General Accounting

1.5. **Workorders**: Please provide a list of work orders by FERC account used for the following types of work in December 2017 and January through November 2018:

   a. Generation
   b. AMI
   c. EDR
   d. LEX
   e. Annual blanket/program work orders (include any work that is a carryover from prior years)
   f. IT
   g. Storms
   h. Joint-owned facilities

1.6. **Workorder**: Please provide a reconciliation of the list of workorders provided in Data Request 1.2 to the amounts included in the December 31, 2018, DCR filing.

1.7. **FERC Form 1 Reconciliations**: Please provide a reconciliation of the Rider DCR balances to the balances in the 2018 FERC Form 1.
1.8. **Budget**: Please provide the 2018 budget supporting the 2018 Compliance Filings. Also, please include the assumptions supporting the budget/projected data.
1.9. **Budget**: Please provide the total actual capital dollars spent and the approved budget by operating company and by functional area (i.e., Transmission, Distribution, General, and Other Plant) for 2018.
1.10. **Status of 2017 Recommendations**: Please provide a narrative on how the companies have addressed the recommendations listed on page 22 in Blue Ridge's Compliance Audit of the 2017 DCR Riders, dated April 21, 2018.
1.11. **DCR Filings**: Please provide a narrative of any changes made to the development process of the 2018 Rider DCR Compliance Filings and schedules from the development process of the 2017 DCR Compliance Filing and schedules.
1.12. **Policies and Procedures**: For each company and the Service Company, please provide any changes for 2018 to the policies and procedures for the following activities.
    a. Plant Accounting
        i. Capitalization, including additions to retirement units of property.
        ii. Preparation and approval of work orders
        iii. Recording of CWIP including the systems that feed the CWIP trial balance
        iv. Application of AFUDC
        v. Recording and Closing of additions, retirements, cost of removal, and salvage in plant
        vi. Unitization process based on the retirements unit catalog
        vii. Application of depreciation
        viii. Contributions in Aid of Construction (CIAC)
    b. Purchasing/Procurement
    c. Accounts Payable/Disbursements
    d. Accounting/Journal Entries
    e. Payroll (direct charged and allocated to plant)
    f. Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)
    g. Insurance Recovery
    h. Property Taxes
    i. Service Company Allocations
    j. Budgeting/Projections
    k. IT projects
1.13. **Policies and Procedures**: Please specifically explain any changes that have been made in capitalization polices that would transfer costs from operating expenses to capital.
1.14. **Internal Audits**: For each company and the Service Company, please provide a list of Internal Audits completed or in-progress for 2018. List the name of the audit, scope, objective, and when the work was performed.
1.15. **SOX Compliance Audits**: For each company and the Service Company, please provide a list of SOX compliance work completed or in-progress during 2018. List the name of the audit, scope, objective, and when the work was performed.
1.16. **Variance Analysis**: For each company, please provide in a Microsoft Excel spreadsheet in FERC Form 1 format the beginning and ending period balance by primary plant (300 account and sub account) for additions, retirements, transfers, and adjustments for 12/1/17 through 11/30/18.

1.17. **Variance Analysis**: For each company, please provide in a Microsoft Excel spreadsheet the beginning and ending period balance for jurisdictional accumulated reserve for depreciation balances by FERC 300 account for 12/1/17 through 11/30/18.

1.18. **Variance Analysis**: For each company and the Service Company, please provide in a Microsoft Excel spreadsheet the beginning and ending period balance of Construction Work in Progress (CWIP) for 12/1/17 through 11/30/18. If the CWIP balances for any of the companies or the Service Company have increased from 12/1/17 to 11/30/18, please provide a narrative and any support documentation explaining the increase.

1.19. **Replacement Programs**: Did the companies have any large construction and/or replacement programs in 2018, such as pole replacement, meters, underground line, etc.? If so, please identify the program, company, and work orders associated with the program.

1.20. **Insurance Recoveries**: For each company and the Service Company, please provide a list of any insurance recoveries charged to capital from 12/1/17 through 11/30/18.

1.21. **Insurance Recoveries**: For each company and the Service Company, please provide a list and explanation of any 2018 pending insurance recoveries not recorded or accrued that would be charged to capital. Indicate the type of recovery, estimated amount, and when receipt is expected.

1.22. **Depreciation**: For each company and the Service Company, please provide the approved depreciation accrual rates by FERC 300 account from 12/1/17 through 11/30/18. Note any changes in rates during the year. Please provide the Commission order that approved the rates for each company and the Service Company.

1.23. **Depreciation**: Does any company use a depreciation rate for any 300 sub-account that has not been approved by the Commission? If so, please provide the following for any changes made in 2018:

   a. FERC 300 account, sub account and company
   b. Depreciation accrual rate used
   c. Analysis supporting the use of the accrual rate
   d. Effective date of the rate
   e. Any filings with the commission for approval

1.24. **Property Tax Rates**: Please provide the supporting documents and calculation for the tax rates used to calculate the actual 11/30/18 and estimated 2/28/19 Rider DCR Revenue Requirement.

1.25. **Approval Signatures**: Please provide the level of signature authority (LOSA) document that supports the approval of capital projects put in service from 12/1/17 through 11/30/18.

1.26. **Exclusions**: Please provide the supporting documentation for the amounts associated with the ATSI Land Lease for actual 11/30/18 and estimated 2/28/19.

1.27. **Excluded Riders**: Please provide the supporting documentation for the amounts excluded from CEI for Rider AMI for actual 11/30/18 and estimated 2/28/19.

1.28. **Excluded Riders**: Please provide the supporting documentation for the amounts excluded for EDR(g).

1.29. **Unitization Backlog**: Please provide, by company, information regarding the backlog in the unitization of workorders for 2018. Please provide the number of workorders and the length of time in months by functional area (i.e., Distribution, Transmission, General, and Other).

1.30. **Unitization Backlog**: Please provide the dollar value of the workorder backlog, by operating company and by workorder classification (Distribution, Transmission, General, and Other).

1.31. **Tax Rates**: Please provide the supporting documentation and calculations for the tax rate used for actual 11/30/18 and estimated 2/28/19.

1.32. **Other Riders**:

a. Has the Company requested and received Commission approval for any riders other than those in the following list?

b. Please confirm that no cost recovered through the following riders has capital additions included within the Rider DCR.

1	Residential Distribution Credit	21	Non-Distribution Uncollectible
2	Transmission and Ancillary Service Rider	22	Experimental Real Time Pricing
3	Alternative Energy Resource	23	Experimental Critical Peak Pricing
4	School Distribution Credit	24	CEI Delta Revenue Recovery – CE
5	Business Distribution Credit	25	Experimental Critical Peak Pricing
6	Hospital Net Energy Metering	26	Generation Service
7	Peak Time Rebate Program – CE	27	Demand Side Management and Energy Efficiency
8	Universal Service	28	Deferred Generation Cost Recovery
9	State kWh Tax	29	Deferred Fuel Cost Recovery
10	Net Energy Metering	30	Non-Market-Based Services
11	Grandfathered Contract – CE	31	Residential Deferred Distribution Cost Recovery
12	Delta Revenue Recovery	32	Non-Residential Deferred Distribution Cost Recovery
13	Demand Side Management	33	Residential Electric Heating Recovery
14	Reasonable Arrangement	34	Residential Generation Credit
15	Distribution Uncollectible	35	Phase-In Recovery
16	Economic Load Response Program	36	Distribution Modernization
17	Generation Cost Reconciliation	37	Government Directives Recovery Rider
18	Fuel	38	Ohio Renewable Resources Rider
19	Delivery Service Improvement	39	Commercial High Load Factor Experimental Time-of Use Rider
20	PIPP Uncollectible	40	Residential Critical Peak Pricing Rider

1.33. **Rider GDR:** The Government Directive Recovery Rider has the potential to impact the Rider DCR.

a. Please provide a list of the costs by FERC account included in the Rider GDR.

b. For any costs charged to FERC accounts included in the Rider DCR, please explain how those costs have been excluded from recovery through the DCR.

1.34. **DMP:** The Distribution Modernization Platform has the potential to impact the Rider DCR.

a. Have the Companies incurred any costs associated with projects that could be recovered through the DMP? If so, please provide the FERC account, description, and amount, when the project began, and if in-service, the in-service date.

b. Please explain how the Companies intend to track projects associated with the DMP to ensure that they are not included within the DCR.

1.35. **Vegetation Management:** Please provide the specific guidance and/or instructions, both financial and operational, provided to field personnel enabling them to determine what routine vegetation work is considered capital or expense.

1.36. **Vegetation Management:** When a company or contractor tree-trimming crew finds a tree or limb, outside the right of way, that needs to be removed while performing unrelated work, how does the crew determine the accounting treatment (capital/expense)?

1.37. **Storm Costs:** How are storm costs monitored to ensure that work is properly classified as capital or expense?

1.38. **Storm Costs:** Is a post-storm review performed on the detail of the project costs for proper accounting classification? If not, why not?

1.39. **Vegetation Management:** Please provide specific information on how tree limb removal, outside the scope of normal tree trimming, has reduced storm outages in duration and cost.
1.40. **Vegetation Management:** How is normal Vegetation Management distinguished from incremental Vegetation Management?
1.41. **Vegetation Management:** Please indicate the person(s) from the Company who can discuss the Company programs for Vegetation Management.
1.42. **Vegetation Management:** Are work orders designated VMPL-DIST by operating Company the only Vegetation Management work orders included in the DCR? If not, please provide the Vegetation Management work order numbers, by operating Company, that are included in the DCR.

Data Request Set 2 (Submitted January 25, 2019)

2.1. **Rider EDR(g):** Follow-up to BRC Set 1-Int-28. Please explain the change in the following highlighted accounts from 11/30/2017 and 11/30/2018. Specifically, explain why the amount gross plant excluded from the Rider DCR decreased from last year.

	Actual as of 11/30/2018		Actual as of 11/30/2017		Difference	
	CEI		CEI		CEI	
FERC Account	Gross	Reserve	Gross	Reserve		
353	$ 287	$ (708)	$ 287	$ (714)	$ -	$ 5
356	$ (1)	$ 19	$ 2	$ 19	$ (3)	$ (0)
358	$ 95,807	$ 4,709	$ 158,578	$ 1,967	$ (62,771)	$ 2,742
360	$ -	$ -	$ -	$ -	$ -	$ -
362	$ (13,799)	$ 1,105	$ 10,968	$ (7,285)	$ (24,767)	$ 8,390
364	$ (36,477)	$ (8,812)	$ (36,477)	$ (2,081)	$ -	$ (6,731)
365	$ (19,816)	$ (2,881)	$ (19,816)	$ 1,706	$ -	$ (4,588)
366	$ -	$ 1,905	$ 58,187	$ 9,668	$ (58,187)	$ (7,763)
367	$ 226,374	$ 14,841	$ 133,412	$ (1,909)	$ 92,962	$ 16,750
368	$ (74,603)	$ (3,827)	$ (74,603)	$ (179)	$ -	$ (3,648)
369	$ (1,537)	$ (90)	$ (1,334)	$ 954	$ (203)	$ (1,044)
370	$ (0)	$ 1,357	$ 23,997	$ (921)	$ (23,997)	$ 2,278
371	$ (6,159)	$ (1,246)	$ (6,159)	$ (491)	$ -	$ (756)
373	$ (2,721)	$ (592)	$ (2,721)	$ 225	$ -	$ (816)
390	$ (0)	$ 226	$ 3,428	$ 2,215	$ (3,428)	$ (1,989)
Grand Total	$ 167,355	$ 6,005	$ 247,748	$ 3,175	$ (80,394)	$ 2,830

2.2. **Rider EDR(g):** Follow-up to BRC Set 1-Int-28. Please explain why the following highlighted accounts are expected to increase from 11/30/2018 to 2/29/2019. Specifically, explain why, after an $80,394 decline in the amount excluded from Rider DCR from 2017 to 2018, there is an expected increase from 11/30/2018 to 2/28/2019.

FERC Account	11/30/18		2/28/19		Difference	
	Gross Plant	Reserve	Gross Plant	Reserve	Gross Plant	Reserve
353	$ 287	$ (708)	$ 1,402	$ (705)	$ 1,115	$ 4
356	$ (1)	$ 19	$ (1)	$ 19	$ -	$ (0)
358	$ 95,807	$ 4,709	$ 98,171	$ 5,194	$ 2,364	$ 485
360	$ -	$ -	$ 9,234	$ -	$ 9,234	$ -
362	$ (13,799)	$ 1,105	$ (7,665)	$ 1,056	$ 6,134	$ (48)
364	$ (36,477)	$ (8,812)	$ (36,383)	$ (9,236)	$ 94	$ (423)
365	$ (19,816)	$ (2,881)	$ (18,646)	$ (3,068)	$ 1,171	$ (187)
366	$ -	$ 1,905	$ -	$ 1,905	$ -	$ -
367	$ 226,374	$ 14,841	$ 227,536	$ 16,226	$ 1,162	$ 1,384
368	$ (74,603)	$ (3,827)	$ (74,599)	$ (4,369)	$ 4	$ (543)
369	$ (1,537)	$ (90)	$ (1,537)	$ (106)	$ -	$ (17)
370	$ (0)	$ 1,357	$ 557	$ 1,360	$ 558	$ 2
371	$ (6,159)	$ (1,246)	$ (6,159)	$ (1,300)	$ -	$ (53)
373	$ (2,721)	$ (592)	$ (2,708)	$ (617)	$ 13	$ (25)
390	$ (0)	$ 226	$ (0)	$ 226	$ -	$ (0)
Grand Total	$ 167,355	$ 6,005	$ 189,203	$ 6,584	$ 21,849	$ 579

2.3. **Rider DMP:** Follow-up to BRC Set 1-34.

a. Please describe the type of projects that will be recovered through the DMP and how these are different from projects recovered through the DCR.
b. Will the DMP projects use the same plant accounts (FERC 300) as projects recovered through the DCR? If not, please describe any differences.
c. Please provide the written criteria that will be used to determine the difference between Capital projects recovered through the DMP vs. DCR.
d. Please describe the control/process mechanism that will be used to ensure that projects are correctly recovered through the DMP vs. the DCR.
e. What specific coding or identification in the accounting system, and specifically in the Power Plant System, will be used for the platform work in the DMP?
f. Are there specific Capital program/project or work order numbers that will be used for DMP projects? If so, please provide.

2.4. Experimental Company Owned LED Lighting Program Costs:

a. How does the Company identify Experimental Company Owned LED Lighting Program costs to ensure that they are excluded from Rider DCR?
b. Are there specific Capital program/project or work order numbers that will be used for the Experimental Company Owned LED Lighting Program projects? If so, please provide.
c. What plant accounts (FERC 300) will be used?

2.5. Government Directive Recovery Rider (Rider GDR):

a. How would the Company identify projects that would be recovered through the Government Directive Recovery Rider?
b. Are there specific capital program/project or work order numbers that will be used for Government Directive Recovery projects? If so, please provide.
c. What plant accounts (FERC 300) will be used?

2.6. **AMI**: Follow-up to BRC Set 1-INT-27. Please explain the decrease in the AMI exclusions from 11/30/17 to 11/30/18 as shown in the following table.

FERC Account	11/30/18		11/30/17		Difference	
	CEI		CEI		CEI	
	Gross	Reserve	Gross	Reserve	Gross	Reserve
303	$ (1,279,852)	$ (292,720)	$ (1,159,454)	$ (174,266)	$ (120,397)	$ (118,454)
362	$ 5,384,748	$ 2,257,238	$ 5,384,748	$ 1,718,763	$ -	$ 538,475
364	$ 163,082	$ 66,199	$ 169,310	$ 55,885	$ (6,227)	$ 10,314
365	$ 1,801,510	$ 1,152,779	$ 1,839,568	$ 971,861	$ (38,057)	$ 180,918
367	$ 11,080	$ 4,363	$ 11,080	$ 3,255	$ -	$ 1,108
368	$ 185,568	$ 118,285	$ 185,568	$ 99,728	$ -	$ 18,557
370	$ 16,821,526	$ 8,628,263	$ 17,090,137	$ 6,968,857	$ (268,610)	$ 1,659,406
397	$ 4,730,254	$ 2,136,239	$ 4,766,987	$ 1,816,481	$ (36,733)	$ 319,758
Grand Total	$ 27,817,917	$ 14,070,645	$ 28,287,943	$ 11,460,564	$ (470,026)	$ 2,610,082

2.7. **AMI:** Please provide a reconciliation between the amounts recovered through the Rider AMI and the amounts excluded in the DCR as of 11/30/2018.

2.8. **ATSI:** Follow-up to BRC Set 1-INT-26. The following table provides the change in ATSI excluded from the DCR based on incremental activity.

Description	CEI	OE	TE	Total
Case No. 07-551-EL-AIR				
Staff Report	$ 64,744,646	$ 93,234,013	$ 17,061,251	
Exhibit TJF-1	$ (7,478,215)	$ (7,943,389)	$ (1,432,451)	
Staff Agrees	$ 57,266,431	$ 85,290,624	$ 15,628,800	$158,185,855
12/31/2011 Rider DCR Amounts	$ 57,266,431	$ 85,290,624	$ 15,628,800	$158,185,855
12/31/2012 Rider DCR Amounts	$ 57,227,343	$ 85,471,094	$ 15,628,438	$158,326,875
12/31/2013 Rider DCR Amounts	$ 59,306,092	$ 86,963,323	$ 16,373,799	$162,643,214
11/30/2014 Rider DCR Amounts	$ 57,224,624	$ 85,567,532	$ 15,628,438	$158,420,594
11/30/2015 Rider DCR Amounts-Corrected	$ 56,418,950	$ 86,956,515	$ 15,628,438	$159,003,903
11/30/2016 Rider DCR Amounts-Corrected	$ 56,405,971	$ 86,982,409	$ 15,628,512	$159,016,892
11/30/2017 Rider DCR Amounts	$ 56,405,971	$ 86,977,415	$ 15,628,438	$159,011,823
11/30/2018 Rider DCR Amounts	$ 56,400,739	$ 86,977,415	$ 15,628,438	$159,006,592
Change from 2017 to 2018 (Incremental Activity)	$ 5,231	$ -	$ -	$ 5,231
Difference 2018 vs Case 07-551-EL-AIR	$ (865,692)	$ 1,686,791	$ (362)	$ 820,737

The next table compares the ATSI excluded from the DCR to the balances in Attachment 1 BRC Set 1-INT-26.

Description	CEI	OE	TE	Total
Case No. 07-551-EL-AIR				
Staff Report	$ 64,744,646	$ 93,234,013	$ 17,061,251	
Exhibit TJF-1	$ (7,478,215)	$ (7,943,389)	$ (1,432,451)	
Staff Agrees	$ 57,266,431	$ 85,290,624	$ 15,628,800	$ 158,185,855
Staff Report	$ 64,744,646	$ 93,234,013	$ 17,061,251	$ 175,039,910
Change from 2011-2018	$ (865,692)	$ 1,686,791	$ (362)	$ 820,737
	$ 63,878,954	$ 94,920,804	$ 17,060,889	$ 175,860,647
BRC 1-26, Attachment 1	$ 63,960,802	$ 95,243,936	$ 17,247,852	$ 176,452,590
Difference	$ 81,848	$ 323,132	$ 186,963	$ 591,942

Please reconcile and explain the differences between the balances for Transmission Plant 350 Land and Land Rights provided in the BRC Set 1-INT-26 Attachment 1 and the amounts excluded from the DCR. Specifically, why is the balance on BRC Set 1-INT-26 Attachment 1 in FERC 350 as of November 2018 higher than the amount excluded from the DCR. Please explain why this higher amount should not be excluded from the DCR.

2.9. **Annual DCR Revenue:** Reference DCR Compliance filings dated January 1, 2019, page 57. Please provide supporting documentation for the Annual Revenue Thru 11/30/2018 for each operating company.

Data Request Set 3 (Submitted January 31, 2019)

3-1. **Priority Data Request -** For the attached work order list (BRC Set 3 - 2018 Workorders SAMPLE Confidential.xlsx), please provide the following information in Microsoft Excel spreadsheets.

a. A work order sample summary.
   i. The individual work order or project approval, written project justification, including quantification of efficiency and cost savings, present value analysis, and/or internal rate of return calculations for projects other than annually budgeted work orders.
   ii. The individual work order or project estimated and actual in-service dates with explanations for delays > 90 days.
   iii. The individual work order or project, budget vs. actual costs, with explanations for cost variances +/- 15%.
   iv. If the information in a i-a iii cannot be provided individually please provide the information requested in item b. below.

b. A report at a project level with a reference to the sample workorder that includes
   i. Approval
   ii. Project justification
   iii. Budget and actual costs with explanation for cost variances +/- 15%
   iv. Estimated and actual in-service dates with explanation for delays > 90 days.

c. Estimates for cost of construction, (material, labor), AFUDC, overheads, retirements, cost of removal, salvage and CIAC's.

d. Supporting detail for assets (units and dollars by FERC account for all FERC accounts within the workorder) added to utility plant from the Power Plant system.

e. Supporting detail for retirements, cost of removal and salvage, if applicable, charged or credited to plant (units and dollars) for replacement workorders from the Power Plant system.

f. An updated list of cost elements

g. Cost element detail that shows the individual workorder, FERC account, and amount as selected in the sample. Considering that a workorder may consist of more than one FERC account, the cost element detail can also include other WBS or Projects as long as the individual FERC account charge selected in the sample is visible.

Data Request Set 4 (Submitted February 4, 2019)

4.1. Follow-up to Data Request response BRC Set 1-INT-10, Rec 10. Please provide detailed support for the following statements:

a. Para 5 of response: "The Companies have had discussions with other utilities, as well as EPRI and other entities, regarding the capitalization of these costs contemplated in the Companies' accounting guidance. These industry peers and experts have consistently agreed that the capitalization of these costs is appropriate and have supported the Companies' policy".
b. Para 2 of response: ". . . insight from advisors, benchmarking industry peers . . ."

4.2. Follow-up to Data Request response BRC Set 1-INT-30. CEI – Distribution backlog over 15 months. Why is the sum of the backlog a negative: ($1,806,067)?

4.3. Follow-up to Data Request responses BRC Set 1-INT-29 and Set 1-INT-30. Please explain what steps were taken to reduce the work order unitization backlog from 3039 work orders and approximately $39.9m as of 12/31/17 to 1407 work orders and approximately $14.1m as of 12/31/18.

4.4. Follow-up to Data Request response BRC Set 1-INT-37 and Attachment 1.
a. Have any updates been made to the Storm Accounting policies and procedures since 1/1/11?
b. Please provide the settlement rules for the most recent storm or the most recent storm where work was completed.
c. Are capitalized storm damage costs recovered through the DCR?

4.5. Follow-up to Data Request response BRC Set 1-INT-38. Please provide the post-storm review for the most recent storm or the most recent storm where work was completed.

4.6. Follow-up to Data Requests BRC Set 1-INT-14, Attachment 1, and Set 1-INT-15, attachment 1-3. Please confirm that the information as requested covers all audit and SOX compliance work performed by the Company for CEI, OE, TE, and FE in 2018. If not, please provide a list of the additional audits and SOX work performed.

4.7. Follow-up to Data Request response BRC Set 1-INT-014, Attachment 1. For the following audits, please provide the executive summary of findings and recommendations. For projects that are in-progress, provide the same information when it becomes available.
a. Line 7: Sarbanes-Oxley Annual Progress Report as of December 31, 2017
b. Line 8: Audit of Accounts Payable for the Year Ended December 31, 2017
c. Line 10: Sarbanes-Oxley 404 Assessment of Internal Controls Over Financial Reporting as of December 31, 2017
d. Line 11: Audit of the Distribution Portfolio Planning Process
e. Line 12: First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2018
f. Line 16: Q2 2018 Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting
g. Line 17: Tax Reform - Deferral Accounting
h. Line 18: Q3 2018 Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting
i. Line 21: Accounting for Capital & Maintenance Costs
j. Line 24: IT asset Management (in-progress).
k. Line 28: Pre-Implementation Review Operational Technology Configuration Management- Phase II (in-progress).
l. Line 30: CREWS Modernization Pre-Implementation Review. (in-progress).

4.8. Follow-up to Data Request BRC Set 1-INT-015, Attachments 1 and 2. For the following SOX compliance audits, please provide a summary of any significant control deficiencies, along with how those deficiencies were corrected or mitigated:

a. Property Accounting: All Control ID's. (Attachment 2)

b. FEU Accounting policy and services: All Control ID's. (Attachment 1).

4.9. Follow-up to 1-INT-002, Attachment 1, and 1-INT-005, Attachment 1. The following table was pulled from AMI workorders included in the workorder population.

Company	FERC Plant Account	Work Order	Work Order Description	Type	Date	Total Activity
CECO	303 - Misc intangible plant	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	-$298,628
CECO	391 - Office furniture, equipment	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	$298,628
CECO	365 - Overhead conductors, devices	996277	AMI Closeout	Replacements	4/30/15	-$115,667
CECO	391 - Office furniture, equipment	996277	AMI Closeout	Additions	4/30/15	$115,667
CECO	365 - Overhead conductors, devices	CE-004000-SG-29	SGMI Data Integration	Replacements	6/1/15	-$102,824
CECO	391 - Office furniture, equipment	CE-004000-SG-29	SGMI Data Integration	Additions	6/1/15	$102,824

a. Please explain the reclassifications in the above table.

b. Please explain why Office Furniture and Equipment was charged to an AMI workorder

c. Are the reclassifications for Phase I or Phase II AMI?

d. Are the costs recovered through the DCR or the AMI Rider? If recovered through the DCR, please justify why it is appropriate to recover the costs through the DCR.

4.10. Follow up to 1-INT-002 Attachment 1. For the below list of workorders, please provide work order descriptions and dates.

Company	FERC Plant Account	Work Order	Work Order Description	Type	Date	Total Activity
OECO	391 - Office furniture, equipment	ZZ_LIFE_AUTO		Replacements		(1,320,953.90)
OECO	393 - Stores equipment	ZZ_LIFE_AUTO		Replacements		(35,927.67)
OECO	394 - Tools, shop, garage equipment	ZZ_LIFE_AUTO		Replacements		(401,666.55)
OECO	395 - Laboratory equipment	ZZ_LIFE_AUTO		Replacements		(243,713.27)
OECO	397 - Communication equipment	ZZ_LIFE_AUTO		Replacements		(200,925.04)
OECO	398 - Miscellaneous equipment	ZZ_LIFE_AUTO		Replacements		(41,438.99)

~~4.11. Follow-up to 1-INT-002, Attachment 1. Please refer to the attached (BRC Set 4 - 2018 Blanket Workorders Confidential) and provide dates for each of the work orders that identify the Date as Blanket.~~

4.12. Follow-up to 1-INT-002, Attachment 1. The work order population that support the Rider DCR under review appear to include approximately $7 million of work orders with dates outside of the 12/1/17–11/30/18 audit scope. Please explain why these work orders dollars are included in the work order population.

4.13. Follow-up to 1-INT-002, Attachment 1, 1-INT-005, Attachment 1, and 1-INT-006, Attachment. 1. The Response to 1-INT-002 (the workorder population) provides this explanation:

> The work orders classified as "Rider DCR in AMI Depreciation Groups" should be a part of the Rider DCR work order population included in "BRC Set 1-INT-002 Attachment 1 – Confidential" but, due to their placement in AMI depreciation groups, are not included in that file. See "BRC Set 1-INT-002 Attachment 2 – Confidential" for this detail.

The workorder population in 1-INT-002, Attachment 1, appears to include AMI workorders that were provided in 1-INT-005, Attachment 1 (list of AMI Workorders). Please explain why there are 58 AMI work orders, totaling $607,816 (see Table 1 below), that are in the population if the reconciliation states they were excluded.

CECO	**Total Activity 2018**
1-INT-002 Attachment 1 - Population	$101,716,513
1-INT-006 Attachment 1 - Excluding SmartGrid (Tab CEI: Cell C64 – “Grand Total Excluding Smart Grid”)	$101,716,513
1-INT-005 Attachment 1 - AMI workorders found within Population	$607,816

Case No. 18-1542-EL-RDR
2018 Annual Compliance Audit of Capital Recovery Rider (DCR) of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

List of AMI Workorders found within 1-INT-002 Attachment 1 (Population)

FERC PLANT ACCOUNT	WORK ORDER	WORK ORDER DESCRIPTION	TYPE	DATE	TOTAL ACTIVITY
370 - METERS	990274	SGMI CBS Phase-2 Closeout	Additions	4/30/15	$210,957
391 - OFFICE FURNITURE, EQUIPMENT	996102	SGIG Project Mgmt - VVC Line	Additions	6/1/15	$35,618
391 - OFFICE FURNITURE, EQUIPMENT	996283	DC Design	Additions	5/13/15	$120,397
391 - OFFICE FURNITURE, EQUIPMENT	CE-004000-SG-33	SGMI Data Collection	Additions	5/13/15	$79,459
303 - MISC INTANGIBLE PLANT	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	-$298,628
303 - MISC INTANGIBLE PLANT	992316	OH IT Itron Upgrades 2018	Additions	Blanket	$7,618
303 - MISC INTANGIBLE PLANT	992317	OH IT AMI Enhancements 2018	Additions	Blanket	$7,833
361 - STRUCTURES AND IMPROVEMENTS	996215	Lark - Net/Comm Construction	Additions	6/27/12	$843
361 - STRUCTURES AND IMPROVEMENTS	996233	Milgate - Net/Comm Construction	Additions	6/29/12	$428
361 - STRUCTURES AND IMPROVEMENTS	996250	Ruth - Substation Construction	Additions	6/27/12	$2,507
361 - STRUCTURES AND IMPROVEMENTS	996408	Oxford Substation Closeout	Replacements	8/3/11	-$44
362 - STATION EQUIPMENT	14341103	Equip Investigate / Repair Miscellaneous	Replacements	6/16/15	-$2,947
362 - STATION EQUIPMENT	996206	Procure Substation Equipment	Additions	6/29/12	$297
362 - STATION EQUIPMENT	996219	Oxford - Procure Network Equipment	Additions	8/3/11	$2,039
362 - STATION EQUIPMENT	996269	Nash - Substation Construction	Additions	9/28/12	$299
364 - POLES, TOWERS AND FIXTURES	15661307	1-OX Install new SGMI recloser #108	Additions	6/16/18	$6,439
365 - OVERHEAD CONDUCTORS, DEVICES	15661307	1-OX Install new SGMI recloser #108	Additions	6/16/18	$53,168
365 - OVERHEAD CONDUCTORS, DEVICES	991435	CEI DA/VVC Eqp Upgrade/Replace	Additions	Blanket	$16,634
365 - OVERHEAD CONDUCTORS, DEVICES	996200	Procure DA Equipment	Additions	6/29/12	$1,285
365 - OVERHEAD CONDUCTORS, DEVICES	996255	DA1 Lab Procure Equipment	Additions	6/29/12	$7
365 - OVERHEAD CONDUCTORS, DEVICES	996277	AMI Closeout	Replacements	4/30/15	-$115,667
365 - OVERHEAD CONDUCTORS, DEVICES	996441	OH DA - Distribution Equipment	Additions	5/14/15	$546
365 - OVERHEAD CONDUCTORS, DEVICES	CE-004000-SG-29	SGMI Data Integration	Replacements	6/1/15	-$102,824
368 - LINE TRANSFORMERS	13060042	SGMI Capacitor Install L-3-NW	Additions	11/25/13	$1,295
368 - LINE TRANSFORMERS	996201	Procure VV Equipment	Additions	6/27/12	$778
368 - LINE TRANSFORMERS	996439	OH VVC- Distribution Equipment	Additions	5/30/15	$70,931
370 - METERS	13205760	Residential Upgrade - Revamp	Additions	8/23/11	$10
370 - METERS	13205775	Residential Upgrade - Revamp	Additions	8/24/11	$17
370 - METERS	13205783	Residential Upgrade - Revamp	Additions	8/23/11	$14
370 - METERS	13210507	Residential Upgrade - Revamp	Additions	9/21/11	$5
370 - METERS	13210514	Residential Upgrade - Revamp	Additions	9/7/11	$3
370 - METERS	13242096	Residential Upgrade - Revamp	Additions	10/10/11	$33
370 - METERS	13242097	Residential Upgrade - Revamp	Additions	10/31/11	$12
370 - METERS	13257481	Residential Upgrade - Revamp	Additions	10/24/11	$13
370 - METERS	13257491	Residential Upgrade - Revamp	Additions	10/24/11	$28

Case No. 18-1542-EL-RDR
2018 Annual Compliance Audit of Capital Recovery Rider (DCR) of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

FERC PLANT ACCOUNT	WORK ORDER	WORK ORDER DESCRIPTION	TYPE	DATE	TOTAL ACTIVITY
370 - METERS	13257494	Residential Upgrade - Revamp	Additions	10/24/11	$11
370 - METERS	13257503	Residential Upgrade - Revamp	Additions	10/21/11	$47
370 - METERS	13257505	Residential Upgrade - Revamp	Additions	10/24/11	$20
370 - METERS	13265422	Residential Upgrade - Revamp	Additions	11/5/11	$62
370 - METERS	13265445	Residential Upgrade - Revamp	Additions	10/26/11	$18
370 - METERS	13265448	Residential Upgrade - Revamp	Additions	10/31/11	$8
370 - METERS	13267271	Residential Upgrade - Revamp	Additions	11/8/11	$14
370 - METERS	13267279	Residential Upgrade - Revamp	Additions	11/12/11	$4
370 - METERS	13267280	Residential Upgrade - Revamp	Additions	11/12/11	$12
370 - METERS	13267290	Residential Upgrade - Revamp	Additions	11/14/11	$14
370 - METERS	13267291	Residential Upgrade - Revamp	Additions	11/14/11	$34
370 - METERS	13269431	Residential Upgrade - Revamp	Replacements	12/13/11	-$3,181
370 - METERS	13284808	Residential Upgrade - Revamp	Replacements	11/28/11	-$218
370 - METERS	13326840	Residential Upgrade - Revamp	Additions	2/25/12	$237
370 - METERS	13326842	Residential Upgrade - Revamp	Additions	2/25/12	$237
370 - METERS	13326843	Residential Upgrade - Revamp	Additions	2/25/12	$237
370 - METERS	13326849	Residential Upgrade - Revamp	Additions	2/18/12	$591
370 - METERS	13331049	Residential Upgrade - Revamp	Additions	3/3/12	$355
370 - METERS	13410124	Residential Upgrade - Revamp	Additions	5/7/12	$331
370 - METERS	991451	SGMI - OH-Post Smrt Mtr Xchg	Replacements	Blanket	-$8,226
370 - METERS	996546	SGMI Phase 1 Meter Repair	Replacements	5/31/13	-$52,331
391 - OFFICE FURNITURE, EQUIPMENT	991961	SGMI-OH Itron AMI Software Upgrade	Additions	8/10/17	$298,628
391 - OFFICE FURNITURE, EQUIPMENT	996204	Procoure Data Integration Equipment	Additions	6/29/12	$222
391 - OFFICE FURNITURE, EQUIPMENT	996277	AMI Closeout	Additions	4/30/15	$115,667
391 - OFFICE FURNITURE, EQUIPMENT	996546	SGMI Phase 1 Meter Repair	Additions	5/31/13	$52,331
391 - OFFICE FURNITURE, EQUIPMENT	CE-004000-SG-29	SGMI Data Integration	Additions	6/1/15	$102,824
397 - COMMUNICATION EQUIPMENT	996203	Procure Net/Comm Equipment	Additions	6/29/12	$373
397 - COMMUNICATION EQUIPMENT	996208	Kepler - Net/Comm Construction	Additions	6/29/12	$94
GRAND TOTAL					**$607,816**

Data Request Set 5 (Submitted February 11, 2019)

5-1. **Vegetation Management:** Follow-up to the Vegetation Management interview conducted on February 7, 2019.

  a. For calendar year 2018, please provide the total vegetation management dollars charged to expense and charged to capital by operating company (CECO, OECO, and TECO).
  b. For calendar year 2018, please provide the total vegetation management dollars budgeted to expense and budgeted to capital by operating company (CECO, OECO, and TECO).
  c. For calendar year 2018, please provide any budget-to-actual variance reports and explanations for actual under or over vegetation management spend against the budget by operating company (CECO, OECO, and TECO) for both capital and expense.

5-2. **Vegetation Management**: Follow-up to the Vegetation Management interview conducted on February 7, 2019. Please provide the assumptions used to develop the 2018 vegetation management capital and expense budgets by operating company (CECO, OECO, and TECO).

5-3. **Vegetation Management:** Follow-up to Vegetation Management interview on February 7, 2019. FirstEnergy indicated that CECO has an incentive program in place for contractors working on Vegetation Management. Please respond to the following related items:

  a. Describe in detail what the incentive program entails, who is part of the program, and any cost-benefit analysis performed in support of the program.
  b. How long has the incentive program been in place?
  c. Provide supporting detail for how the incentive program has benefitted CECO customers.
  d. If the incentive program has provided positive benefits to CECO customers, why have OECO and TECO not adopted similar programs?
  e. If the incentive program has provided positive benefits and no such program has been adopted by OECO and TECO, is the cost of Vegetation Management ultimately providing less benefit to OECO and TECO customers? If not, why not?
  f. What type of activities are part of the incentive program?
  g. Will the incentive program result in more or less dollars charged to capital? Why?
  h. Will the incentive program result in any shift of work either to expense or capital as a result of potential contractor incentives? If so, explain.
  i. Does the incentive program include Company employees? If so, explain how they are included and who is included, what the incentives are, and where they are charged (capital/expense).
  j. Please provide a Vegetation Management summary of operations, by operating company, for the 12 months ended December 31, 2018. If available, the summary should include actual work completed versus the work that was scheduled to be completed with explanations for variances.

5-4. **Vegetation Management:** Follow-up to Data Request response BRC Set 1-INT-035, attachments 1 and 2. Please identify to which graphs on attachment 1 the following attachment-2 activity codes apply and explain how the graphic is applicable to the code.

  a. Code 14: Overhang Limb Removal
  b. Code 05: Off corridor or removal of on corridor tree with overhang
  c. Code 30: Property Owner Notification capital
  d. Code 36: Cut Tree in the Clear Off Corridor No Future Maintenance Required

5-5. **Vegetation Management:** Follow-up to Data Request response BRC Set 1-INT-035, attachment 2. Regarding Activity code 36: Cut Tree in the Clear Off Corridor no Future Maintenance

Required, does this activity code allow the Company to cut any tree, anywhere, as long as the tree is off corridor, and capitalize that activity? If not, explain what activity code 36 is used for?

5-6. **Vegetation Management:** Follow-up to Data Request response BRC Set 1-INT-035. Is any documentation beyond the timesheets with codes from attachment 2 retained to document the vegetation management activity and the decision to charge the costs to capital vs. expense?

5-7. **Pension and OPEB:** ASU 2017-07 amended the accounting for pension and OPEB costs, effective January 1, 2018, to limit the components of net periodic pension and postretirement benefit costs that are eligible for capitalization to only the service costs component. Previously, all components of net periodic pension and postretirement benefit costs (i.e., service cost, interest cost, expected return on plan assets, etc.) were eligible to be capitalized. The result of the accounting changes prescribed in ASU 2017-07 is that the portions of the costs that are no longer eligible to be capitalized increase the Company's operating expenses as compared to prior accounting.

   a. When did the Company adopt ASU 2017-07?
   b. Has the Company modified its policies and procedures to conform to ASU 2017-07? If so, please provide the revised policy and procedure.
   c. Has ASU 2017-07 been reflected in the assets put in service during 2018 and included within the DCR?
   d. Provide the overhead allocation burdens before and after the adoption of ASU 2017-07. Include the calculations of each.

5-8. **Variance Analysis:** Follow-up to Data Request 1-INT-16, Attachment 1 – Confidential. Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following plant accounts:

   a. CEI Account 352 Structures and Improvements—Negative additions of $(11,123)
   b. CEI Account 361 Structures and Improvements—Retirements of $0 although additions of $810,957
   c. CEI Account 397 Communication equipment—Transfer/Adj of $358,449
   d. OE Account 352 Structures and Improvements—Retirements of $0 although additions of $634,023
   e. OE Account 360 Land and land rights—Negative Additions of $(45,784)
   f. OE Account 391 Office furniture, equipment—Negative Additions of $(30,619)
   g. OE Account 397 Communication equipment—Negative Adjustment of $(239,534)
   h. TE Account 367 Underground conductors, devices—Negative Adjustment of $(141,355)
   i. TE Account 368 Line transformers—Adjustment of $150,410
   j. FESC Account 391 Office furniture, equipment—Retirements (greater than additions) of $16,181,476

5-9. **Variance Analysis:** Follow-up to Data Request 1-INT-17, Attachment 1 – Confidential. Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following reserve accounts:

   a. Please explain the decrease in OE Account 373 Street Lighting & Signal Systems from 2017 to 2018 of $1,229,053.
   b. Please explain the increase in OE Account 392 Transportation Equipment from 2017 to 2018 of $216,461.

Data Request Set 6 (Submitted February 12, 2019)

6.1. Reference BRC Set 1-INT-10. The Company response to Rec-17 states, "On November 9, 2018, the Companies filed a Stipulation and Recommendation in Case No. 18-1604-EL-UNC ("Stipulation") which resolves the treatment of the excess deferred income tax balances resulting from the TCJA that was raised by Blue Ridge in the above recommendation. The Stipulation is pending Commission approval. The Companies will implement the Stipulation upon Commission approval."

   a. Please provide the order approving the Stipulation and Recommendation upon Commission issuance.

6.2. Reference the Stipulation and Recommendation filed on November 9, 2018, in Case No. 18-1604-EL-UNC, at page 8.

> a. Normalized EDIT. The Companies will amortize all normalized EDIT net liabilities in accordance with ARAM (average rate assumption method). Rider DCR would reflect the inclusion of the normalized and unamortized non-normalized property EDIT balances as of December 31, 2017 as part of Rider DCR rate base. The Companies will include in the new credit mechanism a return on the cumulative amortized normalized EDIT net liabilities. The return will be calculated in the same manner as Rider DCR.[8]
>
> b. Non-Normalized EDIT. The Companies will amortize non-normalized non-property EDIT balances over a 5-year period and non-normalized property EDIT balances over a 10-year period. The amortization of all EDIT balances will be included in the new credit mechanism.
>
> ---
>
> [8] The normalized EDIT included in the DCR rate base will be fixed at the December 31, 2017 balance, and not be amortized through the DCR. The non-normalized property EDIT included in the DCR rate base will be updated as the balance is amortized.

   1. Please provide "the normalized and unamortized non-normalized property EDIT balances as of December 31, 2017," to be reflected in Rider DCR rate base. What do the Companies' expect the net unamortized non-normalized property EDIT balances in DCR Rider rate base to be as of November 30, 2018, and February 28, 2019?
   2. In reference to the statement, "The Companies will include in the new credit mechanism a return on the cumulative amortized normalized EDIT net liabilities. The return will be calculated in the same manner as Rider DCR," please clarify the intended meaning and demonstrate the underlying mechanics.
   3. Please confirm that (a) the normalized EDIT balances will be reflected in Rider DCR rate base, (b) the valuation will remain fixed as of the December 31, 2017, balance, and (c) the amortization and contra liability will be reflected in the new credit mechanism.
   4. Please confirm that (a) the non-normalized property EDIT balances will be reflected in Rider DCR rate base, (b) the valuation in Rider DCR will be the net unamortized balance, and (c) the amortization will be flowed through to customers via the new credit mechanism.
   5. Where will the non-normalized, non-property EDIT balances and amortization be reflected?

6. Please explain the reason for not synchronizing the EDIT balances, amortization, and contra liabilities together in one rate mechanism. What benefit is realized in exchange for adopting a disjointed approach?

6.3. Reference the Stipulation and Recommendation filed on November 9, 2018, in Case No. 18-1604-EL-UNC at page 9.

> c. <u>EDIT Amount</u>. The actual amount of EDIT flowing back to customers will reflect the final, audited balances, including a federal and state tax gross up, as of December 31, 2017.

1. Please provide "the final, audited balances" owed to customers, *before* and *after* federal and state tax gross up, as of December 31, 2017.
2. Provide a reconciliation of the balances reflected in the DCR rate base and those not reflected in Rider DCR rate base. Indicate where the balances not accounted for in Rider DCR rate base are reflected.
3. Please provide the ADIT balances as of December 31, 2017, *before revaluation* for the federal tax reduction from 35 percent to 21 percent by utility, account, and item type.
4. Please provide journal entries and workpapers supporting revaluation of the ADIT balances as of December 31, 2017, by item type (normalized, non-normalized property, etc.).

6.4. Reference the Stipulation and Recommendation filed on November 9, 2018, in Case No. 18-1604-EL-UNC, at page 9.

> d. <u>EDIT Treatment</u>. The treatment of the EDIT balances will commence effective January 1, 2018 and will continue until the balances have been fully amortized.

1. What is the expected start date and duration over which the new credit mechanism will pass back the 2018 tax savings embedded in base rates and all 2018 EDIT amortizations to customers?
2. Will there be some type of true-up to match the tax savings and EDIT amortization with the corresponding time period?

Data Request Set 7 (Submitted February 20, 2019)

7.1. Follow-up to CONFIDENTIAL Data Request BRC Set 3-INT-1, first partial response dated 2/13/2019. **Attachment 3 (cost detail).**

a. Work order OECO, 13335956: OE- 2012 SCADA Installations. Please explain why AFUDC was 35% of the total charges to the work order.
b. Work order OECO, 132874097: 2012 SCADA install DX feed. Please explain why AFUDC was 34.7% of the total charges to the work order.
c. Work order TECO, 15209359. Equipment investigate repair Transformer. Please explain the $(106,952) credit in other company overheads.
d. For the following work orders, please explain what FERC 300 accounts the CIACs were unitized against, and did the unitizations result in a transfer of CIAC(s) from one FERC account to another? If so, what was the impact on depreciation expense?
    - CECO work order 15821043-CE consolidated unitizations 2017 $2,969,396)
    - CECO work order 15821044-CE consolidated unitizations 2018 $(1,512,889)
    - CEEO work order 15821042-CE consolidated unitizations 2016 $(1,053,374)
    - OECO work order 15821683-OE consolidated unitizations 2017 $(5,670,427)
    - TECO work order 15821701-TE consolidated unitizations 2017 $(1,182,125)

7.2. Follow-up to CONFIDENTIAL Data Request BRC Set 3-INT-1, first partial response dated 2/13/2019. **Attachments 4 and 5 (Retirements and cost of removal).** Please explain why the following work orders have cost of removal charged and no retirements charged.
   a. CECO: 14857540- replace voltage regulator
   b. CECO: 15821043-CE consolidated unitizations 2017
   c. CECO: 15821044-CE consolidated unitizations 2018
   d. CECO: 15821042- CE consolidated unitizations 2016
   e. CEEO: CE-001312-DO-MSTM – Total distribution line
   f. OECO: 14370674- remove switch gear
   g. OECO: 14777263- I/R breakers
   h. OECO: 15821683-OE consolidated unitizations 2017
   i. OECO: IF-OE-000127-1 –OE Fairlawn replace B001 R02
   j. OECO: OE-002814-DO-MSTM – OE MSTM 9 5/22/18 Storm event
   k. TECO: 15821701- TE consolidated unitizations 2017

7.3. Follow-up to CONFIDENTIAL Data Request BRC Set 3-INT-1, first partial response dated 2/13/2019. **Attachments 4 and 5 (Retirements and cost of removal).**
   a. Please explain why CEEO: Work Order IF-CE-000081-1 CE-NRHQ Rpl Diesel Generator has retirements charged but no cost of removal.
   b. Please explain why CECO Work order 13287497- 2012 Scada install DX feed has no retirements or cost of removal charged.

7.4. **EDR(g):** Follow- up to Data Request BRC Set 2-INT-1 and attachment 1. The data request requested an explanation why the EDR(g) amount of gross plant excluded from the DCR decreased from last year. The Companies provided screenshots of the work order activity. The Power plant screen prints supporting the changes in each CECO work order, by FERC account, from 2017 to 2018 indicate a UADD activity code which is additions to FERC 106 -completed construction not classified from FERC 107 - CWIP. Please provide a more detailed explanation why that activity code created credits and supports the change in the FERC account balances from 2017 to 2018.

7.5. **Vegetation Management**: Please provide a sample of three vegetation-management (non-storm) related time sheets with coding for expense activity and capital activity from each operating company.

7.6. **Vegetation Management** Please provide a screen print from the vegetation management system that demonstrates the information available documenting prior vegetation management activity that would be reviewed prior to beginning current work in that corridor.

7.7. **Vegetation Management** Please elaborate on the process used to ensure that a tree trim that was initially charged to capital would have the next trim charged as an expense. What internal controls are in place to ensure that the process is followed?

7.8. **Vegetation Management** What months of the year is most of the normal (non-storm) tree trimming activity performed? Are tree trimming activities being done now such that field observations could be performed to allow a better understanding of the review and subsequent coding used to determine whether an activity is capital vs. expense?

Data Request Set 8 (Submitted February 26, 2019)

8.1. **Prior Recommendations**: Follow-up to DR 1-INT-10. Please provide a copy of the Proper Invoice Review and Approval Flow Chart specified in the Companies response to Blue Ridge's 2017 audit recommendation 3.

8.2. **Unitization**: During the consolidated unitization process, how did the Companies identify work orders that are required to be excluded from the DCR?

8.3. **Unitization**: Follow-up to February 21, 2019, telephone interview with James Radeff—Supervisor Utility Services and Support. Please provide the GL 106 (completed construction not classified) backlog reports (aging detail) for December 31, 2017, and November 30, 2018.

8.4. **Unitization**: Follow-up to the James Radeff telephone interview conducted on February 21, 2019.

   a. Please provide the documentation that was reviewed by PwC related to the consolidated unitization process.
   b. Please provide any written statements issued by PwC that support the conclusion that the process used by the Company to unitize the backlog of work orders was reasonable.
   c. Please provide a summary of the data that was put together by Al Pompeo and approved by the Controller.
   d. Please provide written examples of the review performed by management of the unitization process.
   e. Please elaborate on how the unitization work was assigned to company personnel and contractors.
   f. Please provide the written reports that were produced during the consolidated unitization process.
   g. Please provide the reports that were issued to management during the course of the unitization process.
   h. Please provide a narrative on how the consolidated unitization process would have no effect on the DCR. Explain specifically the effect on plant balances accumulated depreciation and accumulated deferred income taxes.

8.5. **Unitization Backlog**: Follow-up to Data Request response BRC Set 4-INT-002. The Company response said that CEI work orders 996263 and 990272 created a $(2.2m) and $(1.7m) credit, respectively, which accounted for the negative $(1,806,067) Distribution backlog over 15 months. Please provide a description of each work order, including in-service dates, and an explanation for the credit balance of each.

8.6. **Experimental LED Lighting**: Reference BRC 2-INT-004 Attachment 1 and BRC 1-INT-2 Attachment 1. BRC 2-INT-004, Attachment 1, provides a list of Experimental LED Lighting Projects that have been excluded from the DCR. These work orders were compared to the DCR work order population in BRC 1-INT-002, Attachment 1, and the attached list shows $31,411,421 of LED work orders included in the population of DCR work orders. Please explain with supporting documentation how these non-DCR costs were excluded from the DCR.

8.7. **Internal Audits**: Follow-up to Data Request response BRC Set 4-INT-006, attachment 1 - Confidential. The response indicates that if audit reports were not relevant to the DCR, they were not provided in response to Data Request BRC Set 1-INT-015. The scope of the DCR includes any systems that feed into CWIP, which ultimately end up in Electric Plant in Service. Those systems would include, but not be limited to, Payroll, overheads, M&S, and Transportation. Please provide a list, in the same format as provided in response BRC Set 1-INT-014, attachment 1, of any audits performed that relate to a system that feeds into CWIP.

8.8. **AMI:** Follow-up to Data BRC 2-INT-006. The initial request was for an explanation of why AMI decreased, but the Company provided only a list of the work orders. Please provide a narrative on why the AMI exclusion decreased.

8.9. **AMI**: Follow-up to Data BRC 2-INT-006 and BRC 1-INT 2, Attachment 2. The AMI Exclusions (BRC 2-INT-6) do not match the "Rider DCR in AMI Depreciation Groups" work orders provided in BRC 1-INT-2, Attachment 2, by $232,454. Please provide an explanation of the difference.

Data Request Set 9 (Submitted February 27, 2019)

9.1. **AMI**: Follow-up to Data Request response BRC Set 4-INT-009, a–d. For the following AMI-related reclassifications:
   - CECO work order 991961—$298,628 reclassified from FERC 303 to FERC 391.2
   - CECO work order 996277—$115,667 reclassified from FERC 364 to FERC 391.2
   - CECO work order CE-004000-SG-29—$102,824 reclassified from FERC 365 to FERC 391.2.

   a. Please provide a specific description of the assets that were reclassified.
   b. Please provide the detail that demonstrates the AMI related account reclassifications to FERC 391.2 (Data Processing Equipment) were excluded from the DCR.
   c. If the dollars were not excluded from the DCR, please explain why.

9.2. **AMI**: **Follow**-up to Data Request response BRC Set 4-INT-009, a–d. Please provide the detail that demonstrates the depreciation reserve was adjusted as a result of the reclassifications.

9.3. **Variance Analysis:** Refer to attached spreadsheet BRCS WP Work Order to DCR Balance Comparison—Confidential.xlsx. The attached spreadsheet compares the difference of FERC account changes between 11/30/17 and 11/30/18 (taken from the corresponding DCR filings) to the work order population for the same period. Please provide reconciliation with the balances highlighted.

   d. CEI Account 350 difference of $5,231
   e. CEI Account 361 difference of $(3,733)
   f. CEI Account 362 difference of $25,078
   g. CEI Account 364 difference of $(12,667)
   h. CEI Account 365 difference of $144,412
   i. CEI Account 366 difference of $58,187
   j. CEI Account 367 difference of $(92,962)
   k. CEI Account 368 difference of $(73,003)
   l. CEI Account 369 difference of $203
   m. CEI Account 370 difference of $(317,541)
   n. CEI Account 390 difference of $3,428
   o. CEI Account 391 difference of $(805,146)
   p. CEI Account 397 difference of $(37,200)
   q. CEI Account 303 difference of $256,744
   r. OE Account 365 difference of $1,251
   s. TE Account 390 difference of $(1,192,606)
   t. FESC Total difference of $(46,440,917)

Data Request Set 10 (Submitted March 6, 2019)

10-1. **FIELD VISITS**: As a continuation of the audit process, we have selected certain work orders/projects for field verification from the work order sample. The purpose of the field verification is to determine whether the assets have been installed per the work order scope and description. The work order/project selection criteria primarily identified assets that can be physically seen.

Experienced representatives from the Ohio PUC Staff will conduct the field verifications. To assist Staff in that endeavor, please provide, or have available, the following personnel and items:

a. An individual(s) who can coordinate all the field verification with Staff
b. Representatives from FE who can field assist Staff at each field location
c. The Project Manager or a person who was responsible for the work on each project, available to answer Staff's questions
d. Schematics, drawings, or any other visual diagrams that indicate what was built or installed
e. A list of material and/or equipment installed, along with any applicable serial numbers
f. Work order cost data for direct cost (i.e., labor, material, equipment)

If FE has questions about the selection, or any other requirement, please contact Joe Freedman via e-mail at jfreedman@blueridgecs.com or by phone at 607-280-3737.

The following list includes the selected work orders for the field visits:

Cleveland Electric:

1) Work Order: 14857540 Replace voltage regulator
   In-Service Date: 1/29/17
   Net Amount: $1,125,623
2) Work Order: IF-CE-000081-1 - CE - NRHQ Rpl Diesel Generator
   In-Service Date: 1/24/17
   Net Amount: $455,882

Ohio Edison:

3) Work Order: 13287497 - 2012 SCADA Install Dx Feed
   In-Service Date: 5/14/18
   Net Amount: $1,039,577
4) Work Order: 14370674 - SUB REMOVE SWITCHGEAR
   In-Service Date: 5/2/18
   Net Amount: $541,052
5) Work Order: 14565045 - Mod Substation, Tap of Sammis-P
   In-Service Date: 5/8/18
   Net Amount: $3,266,214
6) Work Order: 14777263 - SUB I/R BREAKERS
   In-Service Date: 5/14/18
   Net Amount: $439,207
7) Work Order: IF-OE-000126-1 - OE - Fairlawn Rpl B001 R01
   In-Service Date: 5/1/18
   Net Amount: $345,450
8) Work Order: IF-OE-000127-1 - OE - Fairlawn Rpl B001 R02
   In-Service Date: 5/1/18
   Net Amount: $352,813
9) Work Order: OE-002086-F - 12C Kinsman Paving
   In-Service Date: 11/1/15
   Net Amount: $424,707

Toledo Edison Company:

10) Work Order: 15317256 - TES - RP 138kV ckt switcher
   In-Service Date: 11/7/18

Net Amount: $494,040

Data Request Set 11 (Submitted March 6, 2019)

11-1. **In-Service Dates:** Follow-up to Data Request response BRC 3-INT-001, att 1, Final response 3/26/19 (CONFIDENTIAL). The following three work orders had delayed in-service dates:

- OECO work order 14370674 - REMOVE SWITCHGEAR. The project was scheduled to be in service on 9/1/15 and was in service on 5/14/18. The project was deferred for the following reason: “Project was deferred due to reallocation of labor resources. Not allowed to contract the work.” The project ended up over budget by 243%, or $424,424. The Company explained the cost overrun.
- OECO work order 14565045 - Substation, Tap of Sammis-P. The project was scheduled to be in service on 12/1/16 and was in service on 5/18/18. The project was deferred for the following reason: “Project was deferred due to reallocation of labor resources. Not allowed to contract the work.” The project ended up over budget by 82.2%, or $2,053,039.
- OECO work order 14777263 –Sub. I/R Breakers. The project was scheduled to be in service on 12/30/16 and was in service on 5/14/18. The project was deferred for the following reason: “Project was deferred due to reallocation of labor resources. Not allowed to contract the work.” The project ended up over budget by 246.4%, or $428,998.

The Company explained the increase in cost: “This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.” Please respond to the following related questions:

a. If the projects were delayed, why was the project estimate not updated to reflect technology changes that took place from the time the original budget was established?
b. What additional costs were incurred that would not otherwise have been incurred because of technology changes or any other reason resulting from the delay of the project because of the reallocation of internal labor? If no additional costs, please explain why.

11-2. **(Amended) Budget:** The following blanket work orders were either over or under budget and had the same explanation: ‘Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget for the year.”

- OCEO work order 15519854 - COL-17-17.50 PID 99955 – 128% over budget, $1,193,769.
- OECO work order 15627195 – Brutus P/L cable replacement – 87.1% under budget ($2,976,352).
- OECO work order 15750830 - Urban/ Q2 CBL FLT: – 432,251% over budget $605,324.
- OECO work order 15821822 – Commercial – 66.5% under budget = ($2,510,284).
- OECO work order PA101696420– PO FW – UG Transformer 73BC1D-9C market: 102.10% over budget - $9,304,586.

a. Please explain what “not appropriately allocated across normal work types” means.
b. Please provide support for the statement that the total blanket spend was less than budget for the year.
c. Please explain the impact on the accumulated reserve for depreciation as a result of some FERC 300 accounts over budget and others under budget as a result of the expenditures not properly allocated across normal work types.

11-3. **In-Service Dates:** OECO work orders IF-OE-0001126-1--OE-Fairlawn Rpl B001 R01 and IF-OE-000127-1- Fairlawn Rpl B001-R02 , totaling $345,450 and $352,813 respectively , were completed on 12/31/17 but not placed in-service until 5/1/18. The Company explained the delay was because the work order was not closed timely.

a. What was the impact on the accumulated reserve for deprecation as a result of the 120-day delay in closing the work orders.
b. Was AFUDC stopped when the work was complete on 12/31/17? If not, how much was AFUDC over accrued?

11-4. **Cost of Removal/Retirements:** Follow-up to Data Request response BRC 3-INT-001, att 1, Final response 3/26/19 (CONFIDENTIAL) and attachments 4 and 5 of the interim response to BRC 3-INT-001. Regarding TECO work order 15317256 - TES - RP 138kV ckt switcher, the work order appears, based on the description to be for replacement work. Please explain why no Cost of Removal or Retirements were recorded.

Data Request Set 12 (Submitted March 8, 2019)

12-1. **Backlog**: Follow-up to Data Request BRC Set 4-INT-002. The Company explained that the negative balance in the distribution backlog, $(1,806,067), was created by CEI work orders 996263 and 990272, which had negative balances of $(2.2million) and $(1.7 million), respectively.

a. Please provide descriptions of the work for CEI work orders 996263 and 990272.
b. When were the work orders placed in service?
c. Please provide support for the cause of the negative balances.

12-2. **Consolidated Unitization:** Follow-up to Data Request response BRC Set 3-INT-001 – attachment 3, cost details (CONFIDENTIAL). Please provide a list of the individual work orders and amounts that support the following Consolidation unitization work orders. If individual work orders are not available, please explain why.

a. CECO Work order 15821042 - CE consolidation unitization 2016 - $2,616,182
b. CECO Work order 15821043 - CE Consolidated Unitization 2017 - $10,129,886
c. CECO Work order 15821044 - CE consolidation unitization 2018 - $5,686,341
d. OECO Work order 15821683 - OE consolidation unitization 2017- $11,358,127
e. TECO Work order 15821701- TE consolidation unitization 2017- $1,575,839

Data Request Set 13 (Submitted March 15, 2019)

13-1. **AFUDC:** Follow-up to Data Request response BRC Set 7-INT_001, part a—OECO Work Order 13335956. Please provide the amount of the AFUDC adjustment on the date it will be booked.

13-2. **AFUDC:** Follow-up to Data Request response BRC Set 7-INT_001, part b—OECO Work order 13287497. Please provide the amount of the AFUDC adjustment and the date it will be booked.

13-3. **Over Accrual of Depreciation:** Follow-up to Data Request responses BRC Set 7-INT-002, parts a, e, f, and i. The Company responses explained that "The work order is completed, but not unitized. This work order will be manually unitized (since not fed by a work management system) and the retirement will be done at the time of unitization." Since these work orders were in-service, please provide the estimated over accrual of depreciation for each work order as a result of the delay in recording retirements.

13-4. **Cost of Removal:** Follow-up to Data Request responses BRC Set 7-INT-002, parts b, c, d, h, and k. The Company responses explained, "For the consolidated unitization work orders, the retirements occurred in the original work orders, but the cost of removed charges were transferred to the consolidated unitization work orders."

a. Were the cost of removal charges booked to the original work orders? If so, please provide a further explanation of why the cost of removal charges would be transferred to the consolidation unitization work orders and not stay with the original work orders and, specifically, the retirements to which they relate.
b. If the cost-of-removal charges were not booked to the original work orders, please explain why the retirements were recorded to the original work orders and the costs of removal were not.

13-5. **Unitization:** Follow-up to Data Request responses BRC Set 7-INT-002, parts g and j. The Company responses explained, "The retirement occurred when the work order was manually unitized, which was after 11/30/18 and therefore not included in the BRC Set 3 data."
a. Please indicate what dates the work orders were manually unitized and the amounts of the retirements by work order.
b. Provide any over accrual of depreciation as of 11/30/18 and overstatement of Utility Plant in Service as of the same date.

13-6. **Project Description:** Follow-up to Data Request BRC Set 3-INT-001, OCEO Work order 15750830 - Urban/ Q2 CBL FLT: 4/27/2018. Please provide a project description.

13-7. **Budget:** Follow-up to Data Request BRC Set 3-INT-001, OECO Work Order PA99685200 - PO FW: 59BN4C-531 [MDT Comments SPERLI). This project was 102% over budget. The Company explanation was "Variance results from blanket expenditures not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 10% less than budget for the year." Please provide a more detailed explanation of what "not appropriately allocated across normal work types" means and what if any impacts that has on the work order cost or other work order costs.

13-8. **Vegetation Management**: Follow-up to Data Request BRC Set 5-INT-004. In its explanations of the codes, the Companies mention they consider certain activity to be "an expansion of existing corridor."
a. How does the Company define an expanded corridor and can an expanded corridor exceed 15 feet on each side of a facility, or 30 feet in total? If so, what is the criteria for expansion?
b. How do the Companies maintain record of the fluctuating corridor widths along a single corridor?
c. If the response to 1.a is yes, then overhanging branches or trees just outside the newly expanded limits could require trimming or removal. How do the Companies guard against an ever-expanding corridor?
d. Is the corridor definition of 15 feet on either side of a company facility, or 30 feet in total, required by regulation? If so, cite the regulation, and if not, how was the width determined?
e. Does the Company have a height requirement for a corridor in addition to a width requirement.? If so, what is it, and why is it used?

Data Request Set 14 (Submitted March 18, 2019)

14-1. **Variance Analysis**: In examining the changes in account balances from the 11/30/17 filing to the 11/30/18 filing, Blue Ridge noted the following two accounts whose balances increased significantly. Please provide detailed explanations and documentation to understand these significant increases.

a. CECO account 393 Stores Equipment increased 39.3% from $541,318 to $754,035
b. OECO account 392 Transportation Equipment increased 20.8% from $2,809,715 to $3,393,590

Data Request Set 15 (Submitted March 22, 2019)

15-1. **Consolidated Unitization**: Follow up to Data Request BRC-Set 8-INT-002. If the consolidated unitization process was for all work orders how did the Companies ensure that plant associated with the EDR, AMI, and the Experimental Company-Owned LED Light Program Riders were identified and excluded from the DCR?

15-2. **Consolidated Unitization**: Follow up to Data Request BRC-Set 8-INT-004, attachment 1. The response indicates that a high-level accrual was posted to reverse ~$25 million in expense overheads that were incorrectly applied to orders in the July consolidated unitization.
   a. Is the reversal the same credits shown in the cost detail (3-001, attachment 3) for the consolidated unitization work orders? If not,
   b. How did the Companies identify the A&G overheads that should be applied to CECO, OECO and TECO?
   c. Please identify the Company codes used in the Consolidated Unitization Results table.

15-3. **Unitization Backlog**: Follow up to Data Request BRC-Set 8-INT-005. The company response indicates that 'These work orders are both part of the Ohio Smart Grid (AMI) project. The balances were due to CIAC (contribution in aid to construction) coming in after the project was completed and unitized. Automatic late charge unitization failed and these balances will need to go through the manual unitization process…"
   a. Were the CIAC's recorded in FERC 106 and then the unitization process failed or did the Companies attempt to charge the CIAC's directly to FERC 101?
   b. Did not recording the CIAC result in the over accrual of Depreciation?
   c. Please explain in detail the impact of the CIAC's on the DCR?

15-4. **Experimental Company-Owned LED Light Program**: Follow up to Data Request BRC-Set 8-INT-006, attachment 1 (CONFIDENTIAL). Please explain the impact to the DCR for the $13,356 of remaining LED activity.

Data Request Set 16 (Submitted April 1, 2019)

16.1. Follow up To Data Request BRCS Set 5-INT-004. Please provide the total Vegetation Management dollars charged to the DCR, by work order number, for the period December 31, 2017 through November 30, 2018, for each of the following cost categories.
   a. Cost Category 05 – Off Corridor or removal of on corridor tree with overhang
   b. Cost Category 36 – Cut Tree in the Clear Off Corridor No Future Maintenance Required.
   c. Cost Category 14 Overhand Limb Removal
   d. Cost Category 30 – Property Owner Notification Capital

16.2. Follow up to Data Request BRC Set 12-INT-002, attachment 1 a-e. (CONFIDENTIAL). For the work orders included in the Consolidated Unitizations. Please provide the original in-service, or ready for service, month and year for each work order.

16.3. Depreciation rates: What depreciation rate(s) are used to depreciate work orders closed to FERC 106 and not unitized to FERC 101? Do the Companies use a composite depreciation rate for plant in FERC 106? If so, please provide the rates used?

Data Request Set 17 (Submitted April 4, 2019)

17.1. Follow up to BRC Set 1–Int-10. Status of 2017 Recommendations, Rec-12: The Companies response stated that an adjustment was made in the Companies July 2, 2018, Rider DCR filing regarding the workorders without timely recorded retirements. These adjustments were identified as #16 and #17 in the Companies response to BRC Set1–Int-10, attachment 2. We were unable to find where the effect on the DCR revenue requirements was reflected. Please identify where these adjustments are reflected in the Companies' DCR revenue requirement calculation.

APPENDIX D: WORK PAPERS

Blue Ridge's workpapers are available on a confidential CD. Blue Ridge's analysis included a detailed validation / verification of the Microsoft Excel® spreadsheets provided by FirstEnergy that support the Rider DCR Compliance Filing. The Filing included the following spreadsheets.

- Summary
- DCR Rider Workpaper
- Quarterly Reconciliation
- Billing Units
- Act-Summary
- Act-CEI Sch B2.1 (Plant in Service)
- Act-CEI Sch B3 (Depreciation Reserve)
- Act-CEI Sch B3.2 (Depreciation Expense)
- Act-CEI Sch C3.10 (Property Tax)
- Act-OE Sch B2.1 (Plant in Service)
- Act-OE Sch B3 (Depreciation Reserve)
- Act-OE Sch B3.2 (Depreciation Expense)
- Act-OE Sch C3.10 (Property Tax)
- Act-TE Sch B2.1 (Plant in Service)
- Act-TE Sch B3 (Depreciation Reserve)
- Act-TE Sch B3.2 (Depreciation Expense)
- Act-TE Sch C3.10 (Property Tax)
- Act-Exclusions
- Act-ADIT Balances
- Act-Service Company
- Act-Service Co. Depr Rate
- Act-Service Co. Prop Tax Rate
- Act-Service Co. Incremental
- Act-Intangible Depr Expense
- Est-Summary
- Est-CEI Sch B2.1 (Plant in Service)
- Est-CEI Sch B3 (Depreciation Reserve)
- Est-CEI Sch B3.2 (Depreciation Expense)
- Est-CEI Sch C3.10 (Property Tax)
- Est-OE Sch B2.1 (Plant in Service)
- Est-OE Sch B3 (Depreciation Reserve)
- Est-OE Sch B3.2 (Depreciation Expense)
- Est-OE Sch C3.10 (Property Tax)
- Est-TE Sch B2.1 (Plant in Service)
- Est-TE Sch B3 (Depreciation Reserve)
- Est-TE Sch B3.2 (Depreciation Expense)
- Est-TE Sch C3.10 (Property Tax)
- Est-Exclusions
- Est-ADIT Balances
- Est-Service Company
- Est-Service Co. Depr Rate
- Est-Service Co. Prop Tax Rate
- Est-Service Co. Incremental
- Est-Intangible Depr Expense

Docket No. 18-1542-EL-RDR
Compliance Audit of the 2018 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

Workpapers that support Blue Ridge's analysis are listed below. All workpapers were delivered to PUCO Staff per the RFP requirements.

- WP Vegetation Management Work Orders.xlsx
- WP - AMI Compairson of 2017, 2018 1-INT-1 Att 3, 2-INT-6 and 1-INT-002.xlsx
- WP (T4-Approved Budget) BRC Set 3-INT-001 Attachment 1 and 2- Confidential.xlsx
- WP 2018 BRC Set 1-INT-001 ATT 1 and 3 and 1-INT-006 Comparison.xlsx
- WP AMI BRC Set 2-INT-006 Attachment 1 Confidential.xlsx
- WP AMI BRC Set 2-INT-007 Attachment 1 Confidential.xlsx
- WP ASU_2017-97 Retirement Benefits.pdf
- WP BRC Set 3-INT-001 Attachment 3,4, and 5 Analysis - Confidential.xlsx
- WP BRC Set 12-INT-002 CONFIDENTIAL - Consolidated WOs Bar Graphs.xlsx
- WP BRC Set 12-INT-002 CONFIDENTIAL - Consolidated WOs Outliers and Bands.xlsx
- WP BRC Set 16-INT-001 Compared to Population and 12-INT-002.xlsx
- WP BRCS FE DCR CF Variance 2018—Confidential.xlsx
- WP EDIT Set 6-INT-002 Attachment 1 Confidential.xlsx
- WP FEOH 2018 Adjustments to Plant and Reserve-Confidential REVISED.xlsx
- WP FEOH 2018 Pre-Date Certain Pension Impact Analysis 2012-2018 - CONFIDENTIAL.xlsx
- WP FEOH 2018 Sample Size Calculation Work Orders through 11-30-18 - CONFIDENTIAL.xlsx
- WP FEOH 2018 Workorder Testing Matrix R2.xlsx
- WP Impact of Adjustments BRC Set 1-INT-001 Attachment 1 - FE DCR Compliance Filing 1.2.2019 - Confidential ALL Revised.xlsx
- WP LED Exclusions BRC Set 2-INT-004 Attachment 2 Confidential.xlsx
- WP List of EDR Workorders from 1-INT-002 CONFIDENTIAL.xlsx
- WP V&V FE DCR Compliance Filing 1.2.2019 - Confidential.xlsx
- FE ADIT .xlsx
- WP OAC - 5703-25-05 Definitions.pdf
- WP Ohio Dept of Taxation Annual Report 2018.pdf
- WP ORC - 5727.111 Assessing at percentages of true value.pdf

- Field Observation Worksheets and Photos

- Current Year Interview Notes

The following data responses were obtained in prior audits and were relied upon in the examination of the filings under review in this audit.

- WP FE Response to 2011 Audit Data Request BRC-10-10 and 10-11.pdf
- WP FE response to 2011 Audit Data Request BRC-14-1.pdf
- WP FE Response to 2011 BRC 1-3a - Attachment 1 - Capitalization Policy - Confidential.pdf
- WP FE Response to 2011 BRC 1-3b - Attachment 1 - Work Management Process - Confidential.pdf

- WP FE Response to 2011 BRC 1-3b - Attachment 2 - CREWS Work Request Narratives - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c - Attachment 1 - Creating Multi-Year Enterprise Capital Portfolio - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c – Attachment 2 – FE Capital Portfolio Development and Capital Management Procedure - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c-Attachment 3 - Energy Delivery Capital Allocation Process - Confidential.pdf
- WP FE Response to 2011 BRC 1-3d - Attachment 1 - Accounting For Capitalized Financing Costs During Construction - Confidential.pdf
- WP FE Response to 2011 BRC 1-3e - Attachment 1 - Invoicing Process Flow Chart - Confidential.pdf
- WP FE Response to 2011 BRC 1-3h – Attachment 1 – Procedure for Enterprise Sourcing of Materials and Services - Confidential.pdf
- WP FE Response to 2011 BRC 1-3m – Attachment 1 – Income Tax Policy and Procedure. - Confidential.pdf
- WP FE Response to 2011 BRC 1-3n – Attachment 1 – Ohio Property Tax Returns - Confidential.pdf
- WP FE Response to 2011 Data Request BRC 11-1.pdf
- WP FE Response to 2011 Data Request BRC 11-2.pdf
- WP FE Response to 2011 Data Request BRC 11-3.pdf
- WP FE Response to 2011 Data Request BRCS-11-2.pdf
- WP FE Response to 2012 BRC-1-19 Depreciation Accrual Rates from Staff's Reports.pdf
- WP FE Response to 2012 Data Request BRC-1-19 Depreciation Accrual Rates from Staff's Reports.pdf
- WP FE Response to 2013 BRC Set-1-INT-032 Supplemental - Confidential.docx
- WP FE Response to 2014 BRC Set 1-INT-015 - Confidential.pdf
- WP FE Response to 2014 Data Request BRC-1-5.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 1-Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 2 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 3 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012-Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-013 Attachment 3 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-014.pdf
- WP FE Response to 2015 Audit Data Request BRC Set-13-INT-004.pdf
- WP FE Response to 2016 BRC Set 1-INT-007 Attachment 1 - Confidential.xlsx
- WP FE Response to 2016 BRC Set 1-INT-007 Supplemental.pdf
- WP FE Response to 2016 BRC Set 1-INT-013 - Final Partial Response.pdf
- WP FE Response to 2016 BRC Set 1-INT-013 Attachment 3 - Confidential.docx
- WP FE Response to 2016 BRC Set 2-INT-007.pdf
- WP FE Response to 2016 BRC Set 9-INT-003.pdf

- WP FE Response to 2016 BRC Set 10-INT-001.pdf
- WP FE Response to 2017 BRC Set 1-INT-007 Attachment.xlsx
- WP FE Response to 2017 BRC Set 1-INT-007.pdf
- WP FE Response to 2017 BRC Set 1-INT-011 Attachment.pdf
- WP FE Response to 2017 BRC Set 1-INT-011 Supplemental.pdf
- WP FE Response to 2017 BRC Set 4-INT-002 Attachment.pdf
- WP FE Response to 2017 BRC Set 4-INT-002 Supplemental.pdf
- WP FE Response to 2017 BRC Set 9-INT-004.pdf
- WP FE Response to 2017 BRC Set 11-INT-004.pdf
- WP FE Response to 2017 BRC Set 11-INT-012.pdf

The following personnel had key roles supporting the Rider DCR. Blue Ridge conducted interviews in 2012 (see names with *). For individuals that assumed the role in later years, Blue Ridge requested updates for any change in the role and responsibilities.

Personnel in Key Roles Supporting the Rider DCR

#	Name	Title
1	Douglas Burnell*	Director, Business Services
2	Timothy Clyde* Amy Patterson[232]	Manager, Property Accounting
3	Randal Coleman*	Manager, Distribution Standards
4	Santino Fanelli* Joanne Savage[233]	Manager, OH Revenue Requirements
5	Joseph Loboda[234]* Michele Jones*[235] Sandra Hemberger[236] Teresa Hogan[237]	Manager, Corporate Services Sourcing Manager, Corporate Services Sourcing Director, Corporate Sourcing Director, Corporate Sourcing and Support
6	Thomas McDonnell* Peter Nadel[238]	Manager, Insurance and Operational Risk Management
7	Eileen Mikkelsen[239]* Santino Fanelli[240]*	VP, Rates & Regulatory Affairs Director Rates & Regulatory Affairs

[232] Timothy Clyde was in the position from December 2012 through February 2016. Amy Patterson assumed the position effective February 2016.
[233] As of May 2016, Joanne Savage assumed the position of Manager, Ohio Revenue Requirements that was previously held by Santino Fanelli.
[234] Joseph Loboda was in the position from 1/1/2012 through 2/12/2012.
[235] Michele Jones was in the position from 2/13/2012 through 12/31/2012. Michele Jones left the position of Manager, Corporate Services Sourcing on January 27, 2013. Sandra Hemberger (Director, Corporate Services) kept her existing title, but assumed all of Ms. Jones' responsibilities for corporate services relevant to Rider DCR through the end of 2013.
[236] Michele Jones left the position of Manager, Corporate Services Sourcing on January 27, 2013. Sandra Hemberger (Manager, Corporate Services & Energy Efficiency) kept her existing title, but assumed all of Ms. Jones' responsibilities for corporate services relevant to Rider DCR through the end of 2013.
[237] Teresa Hogan has assumed the role of Sandra Hemberger. Her title is the Director, Corporate Sourcing and Support.
[238] As of February 2016, Peter Nadel assumed Thomas McDonnell's position as Manager, Insurance and Operational Risk Management.
[239] As of May 2016, Eileen Mikkelsen is the VP, Rates & Regulatory Affairs. Eileen Mikkelsen participated in the interview with Erica Millen and Santino Fanelli. No separate interview notes were developed.
[240] Santino Fanelli is the Director of Rates & Regulatory Affairs. The position was previously held by Eileen Mikkelsen.

#	Name	Title
8	Erica Millen* Peter Blazunas[241] Brandon McMillen[242]	OH State Regulatory Analyst
9	John Nauer* Joseph Laboda[243]	Director, Utilities Sourcing
10	Albert Pompeo* James Radeff[244]	FEU Business Services Policy and Control Lead Supervisor, Utilities Services and Support
11	William Richards* Tom Pesich[245] Nicholas Fernandez[246]	Manager, Business Unit Financial Performance Manager, Financial Modeling Director, Strategy and LT Planning[247]
12	Steve Vucenovic* Mark Golden[248]	Manager, General Accounting

*Interview conducted in 2012. Notes provided in previous audit workpapers.

[241] Peter Blazunas replaced Erica Millen. He updated the interview notes from the prior year's audit.
[242] Brandon McMillen assumed Peter Blazunas's responsibilities as it related to Rider DCR. He was interviewed and the notes are included with the workpapers.
[243] Joseph Loboda has assumed the role of John Nauer of the Director, Utilities Sourcing.
[244] James Radeff has assumed the role of Albert Pompeo. His title is Supervisor, Utilities Services and Support.
[245] Starting 11/1/2012, Tom Pesich (Manager, Financial Modeling) assumed the responsibilities for capital forecasting formerly held by Mr. Richards. There was no change to Mr. Pesich's role relevant to Rider DCR in 2013.
[246] Starting 8/22/2014, Nicholas Fernandez (Director, Business Planning & Performance) assumed the responsibilities as it relates to the capital forecast formerly held by Mr. Pesich. There was no change to Mr. Fernandez's role relevant to Rider DCR in 2014.
[247] Nicholas Fernandez is an Executive Director, Strategy and LT Planning as of May 2015. There was no change to Mr. Fernandez's role related to Rider DCR in 2015. In 2018, Nicholas Ferndandez's title changed to Director, Strategy and Long Term Planning and Sustainability.
[248] As of March 2016, Mark Golden assumed Steve Vucenovic's role as it relates to Rider DCR.

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