Docket No. 17-0038-EL-RDR

Compliance Audit of the
2016 Distribution Investment Rider (DIR)
Ohio Power Company d/b/a AEP Ohio

Submitted on August 9, 2017

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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.

This document and the opinions, analyses, evaluations, and recommendations are for the sole use and benefit of the contracting parties. There are no intended third-party beneficiaries, and Blue Ridge shall have no liability whatsoever to third parties for any defect, deficiency, error, or omission in any statement contained in or in any way related to this document or the services provided.

This report was prepared based in part on information not within the control of the consultant, Blue Ridge Consulting Services, Inc. While it is believed that the information that has been provided is reliable, Blue Ridge does not guarantee the accuracy of the information relied upon.

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.
- *Blue Ridge 2016 Recommendations*: This section contains a listing of recommendations resulting from the 2016 DIR audit.
- *Overview of Investigation*: This section provides discussion of the following areas: background; project purpose; project scope; audit standard; information reviewed; brief summary of the variance analyses, transactional testing, and other analyses.
- *Prior Compliance Audit Recommendations' Status*: This section presents the current status of the Companies' implementation of recommendations from prior DIR audits.
- *Findings and Recommendations*: This section documents Blue Ridge's analysis that led to our observations, findings, and recommendations regarding the components that comprise the DIR. In several instances, Blue Ridge used information obtained from the prior audits of the 2012, 2013, 2014, and 2015 DIRs 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.

Footnotes identifying information sources as responses from data requests include the audit year of the data request. For example, data requests issued during the current audit are identified as 2016, corresponding to the period audited.

EXECUTIVE SUMMARY

BACKGROUND

On August 8, 2012, the Public Utilities Commission of Ohio (PUCO or "Commission") issued an opinion and order *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan Case No. 11-346-EL-SSO et al*. In that opinion and order, the Commission established a Distribution Investment Rider (DIR). Through the DIR, AEP-Ohio may recover property taxes, Commercial Activity Tax, and associated income taxes and earn a return on and of plant in service associated with distribution net investment regarding Federal Energy Regulatory Commission (FERC) Plant Accounts 360–374. The net capital additions to be included in the DIR reflect gross plant in-service after August 31, 2010, as adjusted for accumulated depreciation. Capital additions, recovered through other riders authorized by the Commission to recover distribution capital additions, will be identified and excluded from the DIR.

In Case No. 13-2385-EL-SSO, et al., the Commission modified and approved the continuation of the DIR for the period June 1, 2015, through May 31, 2018.

In accordance with the Opinion and Order in Case No. 11-346-EL-SSO and as modified and approved in Case No. 13-2385-EL-SSO, the Commission sought proposals to review the accounting accuracy, prudency, and compliance of Ohio Power Company with its PUCO-approved Rider DIR with regard to in-service net capital additions since the last DIR compliance audit. Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the work.

PURPOSE OF PROJECT

The project purpose as defined in the RFP requires a review of the accounting, accuracy, prudency, and compliance of Ohio Power Company with its Commission-approved DIR with regard to in-service net capital additions since the last DIR compliance audit. The review covers the DIR quarterly filings for 2016. Capital additions, recovered through other riders authorized by the Commission to recover delivery-related capital additions, will be identified to ensure their exclusion from the DIR. The review will also include identification, quantification, and explanation of any significant net plant increases within individual accounts.

PROJECT SCOPE

The project scope as defined in the RFP is to determine whether Ohio Power Company ("AEP-Ohio" or "Company") has implemented its PUCO-approved DIR in compliance with the Opinion and Orders issued in Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO. The audit includes, but is not limited to, the following tasks:

- Review Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO
- Read all applicable testimony and associated workpapers
- Review Plant-in-Service related provisions contained within the Orders in Case Nos. 11-352-EL-AIR and 11-351-EL-AIR
- Obtain and review all additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred for the actual year ended December 31, 2016
- Verify current date value of plant in service with FERC Form 1 for year 2016
- Obtain and review all appropriate documentation relating to the Company's compliance with its PUCO-approved DIR
- Obtain and review all appropriate documentation related to compliance with the Commission's Finding and Orders in Case Nos. 14-255-EL-RDR, 15-66-EL-RDR, and 16-21-EL-RDR

- Field verification of the used and usefulness of incremental plant in service
- Review all changes in capitalization policy and assess any impacts on the DIR, previously authorized recovery as part of base rates, and the impact on O&M expenses
- Assess the Company's utilization of tax changes and provisions and verification of their appropriate treatment within the DIR, including estimating foregone tax reduction opportunities and evaluating the impact on the DIR

FINDINGS AND RECOMMENDATIONS

OVERALL IMPACT OF FINDINGS ON DIR REVENUE REQUIREMENTS

Blue Ridge's review of the accounting, accuracy, prudency, and compliance of Ohio Power Company with its Commission-approved DIR found three issues that require computation by the Company to determine the impact on the DIR.

First, several work orders within the sample reviewed by Blue Ridge included cost elements totaling $138,511 related to costs that are inappropriate for inclusion in the distribution rider. While the $138,511 observed by Blue Ridge would be immaterial to the Company's DIR, it is likely that these cost elements are included within other work orders included within the overall work order population and are, therefore, being recovered through the DIR. Blue Ridge extrapolated the value of the cost elements found in the sample to the population of work orders, resulting in an extrapolated total of $353,207. Blue Ridge extrapolated the finding to the increase in net distribution plant since August 31, 2010, and estimates net distribution plant could be overstated by approximately $1.7 million. Blue Ridge recommends that the Company review the cost detail for the total population of work orders included in the DIR and remove the costs of the following five identified cost elements from the DIR.

1. Cost Element 141: Incentive Accrual Dept. Level—used to record Distribution, Customer Operations and Regulatory Services Incentive Plan expense
2. Cost Element 143: Other Lump Sum Payments
3. Cost Element 145: Stock-based compensation—used to record Performance Share Incentive expense
4. Cost Element 154: Restricted Stock Incentives—used to record Restricted Stock Unit expense
5. Cost Element 155: Transmission Incentives—used to record Transmission Incentive Plant expense

Second, Blue Ridge's review of the standard costs components found that the Standard Fringe Factor is overstated by approximately 15 percent. As this rate is used for the capitalization of meter and line transformer installations and removal costs, its overstatement results in an overstatement in these capital amounts. The Company is developing an analysis of the impact and will provide it later. Blue Ridge recommends that the Company calculate the impact and adjust the DIR.

PROCESSES AND CONTROLS

From the documents reviewed, Blue Ridge was able to obtain an understanding of the Company's processes and controls that affect the DIR. One issue related to Recommendation #4 from last year's report. Responding to the recommendation to attach a form to Lotus Notes® database approval of projects, the Company stated it no longer used Lotus Notes® for approvals. Upon follow-up to this change, Blue Ridge discovered that the Company did not update the Distribution Business Rules for Authorizing Capital Projects in regard to this change. Rather, a new Improvement Requisition Policy and Procedures document was issued in June of 2016 that addresses Capital Projects. Additionally, the AEP Authorization Policy was updated in 2015. The Company stated that the new Improvement Requisition Policy and Procedures supersedes the Distribution Business Rules for Authorizing Capital Projects. Blue Ridge recommends that if the Distribution Business Rules for Authorizing Capital Projects is still in use in its current form, it should make mention within that document of the superseding status of the 2016 new Improvement Requisition Policy and Procedures.

Blue Ridge requested information on any changes to the policies and procedures as specified above. The Company stated that the only change made was to the capitalization policy by which a retirement unit for Energy Control Devices and Displays was established. Blue Ridge recommends that the Company highlight and quantify this and any other changes to the capitalization policy in the DIR filing preceding the implementation of the change.

Blue Ridge was satisfied with actions taken with regard to internal audits and SOX-compliance testing. Blue Ridge concluded AEP Ohio's processes and controls were adequate and not unreasonable.

<u>VARIANCE ANALYSIS</u>

Based on Blue Ridge's review of variances in the Company account balances during the 2016 DIR year, no variances resulted in concerns for the proper calculation of DIR amounts.

In comparing fourth quarter DIR filing with the 2016 FERC Form 1, a minor dollar amount mismatch was found in account 362—Station Equipment. The Company explained the discrepancy satisfactorily. However, while the Company provided the explanation for the difference during discovery, the Company is not in compliance with the Commission's Order to provide the reconciliation within the DIR filing. Blue Ridge recommends that the Company provide the reconciliation to the FERC Form 1 within the DIR filings as ordered by the Commission.

In response to a variance analysis request regarding additions and retirements in account 362, the Company stated that the retirements for a certain work order were incorrectly booked to the installation work order. The Company stated that the related retirement amount would be reclassified to the proper work order. Blue Ridge does recommend that the Company follow through with the reclassification.

<u>REVENUE REQUIREMENTS</u>

<u>Overview of Methodology</u>

In Case No. 11-346-EL-SSO et al., (*ESP 2 Case*) the Company requested a Distribution Investment Rider (DIR) that would allow carrying costs on incremental distribution plant to be recovered each year using a pre-tax weighted average cost of capital and an O&M component. The DIR revenue requirement excluded recovery on plant included in prior base distribution rate cases and plant recovered in other riders. The Commission ordered that the DIR mechanism not include any gridSMART costs. The gridSMART projects are separate from the DIR and are recovered through the gridSMART rider. The DIR also excludes capital dollars spent for vegetation management that are recovered through the Enhanced Service Reliability Rider. Furthermore, the Commission ordered that the DIR mechanism be revised to account for accumulated deferred income tax.

Case No. 13-2385-EL-SSO extended the DIR through May 2018 and incorporated several modifications. The modifications included approval of rate caps for 2015 through May 2018, a revision to the property tax calculation, and modifications to adopt six recommendations by Staff.

Revisions to DIR Ordered in Case No. 13-2385-EL-SSO

With the extension of the DIR, the Commission ordered modifications to the DIR, including the adoption of six recommendations made by Staff, the adoption of OCC's recommendation regarding property taxes, and the inclusion of gridSMART Phase 1 capital costs within the DIR.

Staff recommended detailed account information for excluded riders, particularly gridSMART and the vegetation management included in the ESRR (Enhanced Service Reliability Rider), be provided in the DIR filings. The Company's DIR filing includes a section from the ESRR filing that allows for a review of the cumulative capital spent on vegetation management to the Incremental Vegetation net book value. The Company's DIR filing also includes a workpaper showing the net book value of the gridSMART assets. The gridSMART Phase I rider was based on capital dollars spent, not net book value, so there is no net book value comparison, and the Company was unable to reconcile Net Book Value. The Company implemented a process that showed the amount of capital spent by work order for the Phase I project and compared that to the work orders included in the gridSMART net book value calculation in order to verify that all workorders were properly coded in the owned asset system and the assets associated with the capital being recovered through the Phase I rider were not also being recovered through the DIR.[1] Phase II of gridSMART will be implemented using a net book value calculation, which is different from the way it was done in Phase I.[2] The Company has complied for the ESRR. After the gridSMART I assets are transferred into the DIR, many of the difficulties associated with reconciling the DIR to the gridSMART rider should be resolved.

Staff recommended that AEP Ohio provide the jurisdictional allocations and accrual rates for each account and subaccount that were approved in AEP's prior AIR case, subject to Staff's exception for gridSMART depreciation rates. The Company has complied.

Staff recommended the Company should include in each DIR filing, for each account and subaccount, a full reconciliation between the functional ledger and FERC form filings as well as detailed workpapers showing the jurisdictional allocation, accrual rates and reserve balances of each account and subaccount. The Company has provided the required information. Although the Company stated that it has implemented Staff's recommendation, no reconciliation was included in the DIR filing for a slight discrepancy in its fourth quarter 2016 FERC Form 1 report from the fourth quarter 2016 DIR filing. Blue Ridge recommends that the Company provide the reconciliation in the DIR filings as ordered by the Commission.

Staff recommended the Company be directed to detail the DIR revenue collected by month and to date in its filings to demonstrate compliance with annual revenue caps. The Company did include a workpaper within the DIR filing comparing the monthly and to date DIR revenue with the Billed DIR.

Staff recommended any further changes the Company proposes to its capitalization policy should be highlighted and quantified in the DIR filing. In one data request response, the Company stated that no capitalization policy changes have been reported by the Company since the prior filing. However, part of Blue Ridge's review process is to obtain any changes to the Company's policies and procedures from the prior audit. The Company's update included a change made to the capitalization policy by which a retirement unit for Energy Control Devices and Displays was established. Blue Ridge recommends that the Company highlight and quantify this change and any

[1] AEP Ohio's response to 2016 Data Request 8-008.
[2] AEP Ohio's response to 2016 Data Request 8-008.

other changes to the capitalization policy in the DIR filing preceding the implementation of the change.

Staff recommended the filing of an updated depreciation study by November 2016. The Company filed an updated as required.

OCC recommended, and the Commission approved, a modification to the property tax calculation to adjust the depreciation reserve to eliminate the cumulative amortization of the excess depreciation reserve since rates in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR went into effect. Blue Ridge found, for the purposes of calculating property taxes, the depreciation reserve has been offset as ordered by the theoretical reserve offset.

Mathematical Accuracy

Blue Ridge validated the mathematical calculations in the Company's revenue requirement model for each quarter and found them not unreasonable.

Net Plant in Service

Blue Ridge's review of net plant in service included validation to FERC Form 1 filings for gross plant and the reserve for depreciation. With the exception of a small difference in the fourth quarter 2016, plant balances matched. The Company's explanation of the small difference was not unreasonable.

Regarding transactional testing of sampled work orders, Blue Ridge performed a ten-step testing process to determine the integrity of the DIR in process and intent. Among its findings, Blue Ridge noted the following:

1. Blue Ridge found that the work tested was properly includable in the DIR. However, The Company purchases capital spares based on a specific set of criteria that allows their charge to capital even though the spares are not in service and technically not used and useful. Since the capital spares are related to distribution, the purchases were charged to the proper FERC accounts. The purchase of capital spares is a common practice in the utility industry. Blue Ridge found the capital spare purchases and accounting not unreasonable. Blue Ridge expressed concern whether an asset that was not used and useful should be recovered through the DIR. The Company defended its position that the capital spares are appropriately included in the DIR. However, Blue Ridge recommends further discussion on this issue.
2. Blue Ridge found that the sample did not include any identified gridSMART work orders. Among its sample work orders, Blue Ridge also found gridSMART Phase 1 costs. As the Company would not implement the Commission-approved recovery of gridSMART Phase 1 assets until April 2017, the capital costs associated with gridSMART Phase 2 were appropriately excluded within the DIR calculation. Additionally, Blue Ridge found that all vegetation management work orders had been excluded from the DIR.
3. Blue Ridge reviewed the project approval documentation and found that the Company adhered to its stated approval policy and found that all work orders sampled contained the appropriate approvals.
4. Blue Ridge reviewed work orders in the sample to determine whether the work order packages contained the appropriate project justifications. However, not all projects provided adequate alternative solutions in the project justification. In one particular example of inadequate alternative solutions, Blue Ridge agrees with the Company's selected alternative. However, we recommend that in order to complete the justification process, the Company provide the reason(s) one alternative is better than another and, if savings are estimated, indicate how those savings are to be realized. Additionally, Blue

Ridge recommends the Company document operational and/or economic alternatives and, if no alternatives are considered, document the reason(s).

5. Blue Ridge's review includes an analysis of whether work orders in the sample were within +/-15% of their approved budget. Nine of the 47 work orders tested were over budget by greater than 15%. Blue Ridge found the explanations not unreasonable. As the budget in some instances, such as customer service, is established six months in advance of the budget year, inaccuracy of estimates is a distinct possibility. The inaccuracy potential in establishing the budget six months in advance could result in the actual being over or under the estimate depending on the overall level of actual customer activity for a given year. Some of that activity is customer dependent and, therefore, outside the direct control of the Company. Blue Ridge recommends that the Company continue to manage to the budget and document reasons for overage or underage of actual charges both when those reasons are outside the direct control of the Company and when those reasons are within the direct control of the Company. Therefore, as long as the Company manages the budget and can adequately explain the overage or underage, the variance from budget can be shown as not resulting from lack of management control.
6. Blue Ridge also noted a large project over budget due to an incomplete work plan. Blue Ridge recommends that when large projects are developed, the Company place more emphasis on ensuring the work plan is complete and that the contractors performing the work understand the requirements from both work and safety perspectives.
7. Five cost elements involved in DIR work orders should not, in Blue Ridge's opinion, be considered payroll, payroll-related, or appropriate overhead costs that benefit the project(s). Blue Ridge recommends removing any such costs of these five cost elements from the DIR.
8. The six projects selected for field verification confirmed that the assets were installed and, except for the capital spare in a work order, used and useful.

Additionally, review of backlog and insurance recoveries revealed no unreasonable activity.

Exclusions From DIR

The Commission ordered that capital additions recovered through other Commission-authorized riders be identified and excluded from the DIR Rider. Blue Ridge reviewed each rider and determined that the gridSMART and Enhanced Service Reliability Riders are the only riders that include distribution plant that should be removed from the DIR to avoid double counting. Blue Ridge found the Company excluded capital additions recovered through other Commission-authorized riders from the DIR.

Accumulated Deferred Income Tax

The Commission ordered that the DIR mechanism account for accumulated deferred income tax (ADIT) offset. Blue Ridge found that the ADIT as of December 31, 2016, was related to utility plant and that incremental ADIT was appropriately excluded from the change in Distribution Plant before applying the return component of the carrying charge.

Carrying Charge Rate

The carrying charge rate includes elements to allow the Company an opportunity to recover property taxes and commercial activity tax and to earn a return on (accounting for associated income taxes) plant in service associated with distribution net investment. The carrying charge rate is not unreasonable.

Gross-Up Factor (CAT)

The Rider Revenue Requirements were grossed up for the Commercial Activity Tax (CAT). Blue Ridge found the rate not unreasonable.

Revenue Offset

Blue Ridge found that the Company appropriately increased the DIR revenue requirement by the $62.344 million revenue credit included in the distribution case settlement in Case No. 11-351-EL-AIR.

Annual Cap and Over/Under Recovery

The recovery on the DIR is capped at certain levels each year. Blue Ridge found that the Company did not exceed the $165 million cap for 2016 when adjusted for the over/under recovery for previous years. Blue Ridge found that the Company's methodology for calculating the over or under billed for the DIR was not unreasonable.

Annual Base Distribution Revenue

Blue Ridge compared the screen shots of the query used to determine the base distribution revenues to the amount included within the DIR filings. The 2nd and 3rd quarter DIR filing's base distribution revenue inappropriately excluded the reactive demand of Ohio Power rate zone only (RD06). The exclusion of the reactive demand of Ohio Power rate zone from the Annual Base Distribution Revenues, resulted in the overstatement of Percentage of Base Distribution Revenue reported in the 2nd and 3rd quarter 2016. Blue Ridge recommends that the Company calculate the impact on ratepayers of the over collection of the DIR in the 2nd and 3rd quarter 2016 and adjust the DIR in a future filing.

BLUE RIDGE 2016 RECOMMENDATIONS

For the 2016 DIR assessment, Blue Ridge summarizes its recommendations as follows:

Rec-01. Blue Ridge recommends that work order costs associated with cost elements 141, 143, 145, 154, and 155 be removed from the DIR. These are costs that, in Blue Ridge's opinion, are not payroll, payroll-related, or an appropriate overhead cost that benefits the project(s). (2016 DIR Report, pp. 22–23 and 51)

Rec-02. Blue Ridge recommends that if the Distribution Business Rules for Authorizing Capital Projects is still in use in its current form, it should make mention within that document of the superseding status of the 2016 new Improvement Requisition Policy and Procedures. (2016 DIR Report, p. 32)

Rec-03. Blue Ridge recommends that the Company highlight and quantify the capitalization change regarding the establishment of a retirement unit for Energy Control Devices and Displays and any other changes to the capitalization policy in the DIR filing preceding the implementation of the change. (2016 DIR Report, pp. 32 and 40)

Rec-04. Blue Ridge recommends that the Company, in compliance with the Commission's Order, provide the reconciliation of the DIR account balances to the FERC Form 1 within the DIR filings as ordered by the Commission. (2016 DIR Report, pp. 34 and 39)

Rec-05. Blue Ridge recommends that the Company follow through with the error discovered regarding the retirements for work order 42263333 and reclassify the associated $145,000 to the proper work order. (2016 DIR Report, p. 36)

Rec-06. Blue Ridge recommends that the vegetation management schedule in the DIR include the plant accounts and subaccounts. (2016 DIR Report, p. 38)

Rec-07. Blue Ridge recommends the issue of the Company's inclusion of capital spares in the DIR be given further review. The Company should look into borrowing capital spares, if it makes economic sense, or, at a minimum, perform an analysis to compare renting versus the purchase of a capital asset. (2016 DIR Report, p. 48)

Rec-08. Blue Ridge recommends that the Company, in order to complete the project justification, document all alternatives (operational and/or economic), providing the reason(s) one alternative is better than another and, if savings are estimated, indicate how those savings are to be realized. If no alternatives were considered, document the reason(s) as well (2016 DIR Report, pp. 48–49)

Rec-09. Blue Ridge recommends that the Company continue to manage to the budget and document reasons for overage or underage of actual charges whether those reasons are outside or within the direct control of the Company in order to demonstrate that the budget variance did not result from lack of budget management control. (2016 DIR Report, p. 50)

Rec-10. Blue Ridge recommends that when large projects are developed, the Company place greater emphasis on ensuring the work plan is complete and that the contractors performing the work understand the requirements from both work and safety perspectives. (2016 DIR Report, p. 51)

Rec-11. Blue Ridge recommends the Company continue to monitor inactive work orders that appear on the report, striving to resolve outstanding issues within a reasonable time frame of six months to reduce the total dollar value of inactive work orders. (This recommendation appeared in last year's report. Blue Ridge agrees with the Company that work orders may remain inactive for reasons outside the Company's control, and we acknowledge the Company's statement that monitoring is conducted on the inactive work order report. However, because of the significant duration of some of the inactive work orders, by this recommendation, Blue Ridge is continuing to stress the importance of focus to ensure that outstanding issues able to be resolved are resolved.) (2016 DIR Report, pp. 52–53)

Rec-12. Blue Ridge recommends that the Company correct the Standard Fringe Factor that included the non-productive time rate twice. The impact was an overstatement of the fringe benefit loading rate by approximately 15 percent. As this rate is used for the capitalization of meter and line transformer installations and removal costs, its overstatement results in an overstatement in these capital amounts. The Company is developing an analysis of the impact and will provide it later. Blue Ridge recommends that the Company calculate the impact of the overstatement, and adjust the DIR. (2016 DIR Report, p. 55)

OVERVIEW OF INVESTIGATION

BACKGROUND

On August 8, 2012, the Public Utilities Commission of Ohio (PUCO or "Commission") issued an opinion and order *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan Case No. 11-346-EL-SSO et al*. In that opinion and order, the Commission established a Distribution Investment Rider (DIR). Through the DIR, AEP-Ohio may recover property taxes, Commercial Activity Tax, and associated income taxes and earn a return on and of plant in service associated with distribution net investment regarding Federal Energy Regulatory Commission (FERC) Plant Accounts 360–374. The net capital additions to be included in the DIR reflect gross plant in-service after August 31, 2010, as adjusted for accumulated depreciation. Capital additions, recovered through other riders authorized by the Commission to recover distribution capital additions, will be identified and excluded from the DIR.

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The project purpose as defined in the RFP requires a review of the accounting, accuracy, prudency, and compliance of Ohio Power Company with its Commission-approved DIR with regard to in-service net capital additions since the last DIR compliance audit. The review covers the DIR quarterly filings for 2016. Capital additions, recovered through other riders authorized by the Commission to recover delivery-related capital additions, will be identified to ensure their exclusion from the DIR. The review will also include identification, quantification, and explanation of any significant net plant increases within individual accounts.[3]

PROJECT SCOPE

The project scope as defined in the RFP is to determine whether Ohio Power Company ("AEP-Ohio" or "Company") has implemented its PUCO-approved DIR in compliance with the Opinion and Orders issued in Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO. The audit includes, but is not limited to, the following tasks:

- Review Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO
- Read all applicable testimony and associated workpapers
- Review Plant-in-Service related provisions contained within the Orders in Case Nos. 11-352-EL-AIR and 11-351-EL-AIR
- Obtain and review all additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred for the actual year ended December 31, 2016
- Verify current date value of plant in service with FERC Form 1 for year 2016

[3] Request for Proposal No. RA17-CA-1, *A Compliance Audit of the Distribution Investment Rider of Ohio Power Company*, page 1.

- Obtain and review all appropriate documentation relating to the Company's compliance with its PUCO-approved DIR
- Obtain and review all appropriate documentation related to compliance with the Commission's Finding and Orders in Case Nos. 14-255-EL-RDR, 15-66-EL-RDR, and 16-21-EL-RDR
- Field verification of the used and usefulness of incremental plant in service
- Review all changes in capitalization policy and assess any impacts on the DIR, previously authorized recovery as part of base rates, and the impact on O&M expenses
- Assess the Company's utilization of tax changes and provisions and verification of their appropriate treatment within the DIR, including estimating foregone tax reduction opportunities and evaluating the impact on the DIR[4]

AUDIT STANDARD

Blue Ridge used the following standard during the course of the audit: the audit will review the amounts for which recovery is sought to determine whether they are not unreasonable. Blue Ridge will determine whether the amounts for which recovery is sought are not unreasonable in light of the facts and circumstances known to the Company at the time such expenditures were committed.

INFORMATION REVIEWED

Blue Ridge reviewed the following information as required in the RFP.

- Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO
- All applicable testimony and associated workpapers
- Plant-in-service related provisions contained within the Orders in Case Nos. 11-352-EL-AIR and 11-351-EL-AIR
- All changes in capitalization policy and their impacts, if any, on the DIR and on O&M expenses

For ease of reference, excerpts from the Rider DIR portions of the Orders in the above cases are provided in Appendix A.

Blue Ridge also reviewed audit reports from the prior three audits and related files for Case Numbers 14-0255-EL-RDR, 15-0066-EL-RDR, and 16-21-EL-RDR. Appendix A includes an electronic copy of the audit reports and filings reviewed.

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 were provided to Staff.

RIDER DIR COMPLIANCE FILINGS REVIEWED

The Company filed and Blue Ridge reviewed the following quarterly DIR filings:

1. 1st Quarter 2016 – Case No. 14-1696-EL-RDR filing dated June 28, 2016
2. 2nd Quarter 2016 – Case No. 14-1696-EL-RDR filing dated September 28, 2016
3. 3rd Quarter 2016 – Case No. 14-1696-EL-RDR filing dated December 22, 2016
4. 4th Quarter 2016 – Case No. 14-1696-EL-RDR filing dated May 24, 2017

[4] Request for Proposal No. RA17-CA-1, *A Compliance Audit of the Distribution Investment Rider of Ohio Power Company*, page 2.

Variance Analysis, Transactional Testing, and Other Analysis

To identify, quantify, and explain any significant net plant increases within the individual accounts, Blue Ridge performed account variance analyses. The Company was asked to explain any significant changes. The results of the analysis are included in this report under the section labeled Variance Analysis.

In addition, Blue Ridge selected a sample number 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 that would allow conclusions to be drawn in regard to the total population. Additional work orders were selected based on professional judgment. The results of the transactional testing are included in the section labeled Plant in Service.

Blue Ridge also performed various analyses, including mathematical verifications and source data validation, of the schedules that support the Rider DIR Compliance Filings. The report addresses each component of the DIR and the results of these analyses are included within each component's section.

A list of Blue Ridge's workpapers is included in Appendix D.

PRIOR COMPLIANCE AUDITS RECOMMENDATIONS STATUS

Rider DIR compliance audits have been performed covering each of the years 2012 through 2015. Each report included findings and recommendations and were filed appropriately in Case Nos. 13-0419-EL-RDR, 14-0255-EL-RDR, 15-0066-EL-RDR, and 16-0021-EL-RDR. Blue Ridge performed the Rider DIR compliance audit that covered calendar year 2015. The following list includes recommendations from that audit. Following each recommendation is AEP Ohio's initial comments to the recommendations,[5] the recommendation's status[6] and Blue Ridge's associated comments based upon observations from this compliance audit.

Recommendation 1: Blue Ridge recommended, should the Company receive the refunds being pursued as a result of the vendor contract audits' determination of overpaying vendors for services, the DIR of the year in which the refund is received should reflect the appropriate impact of the refund(s).

AEP-Ohio Initial Comment:

While the Company agrees that the adjustment should flow through the DIR, the Company disagrees that the amounts are material enough to restate prior years. There were two values associated with the recommendation, one related to January 2012 through February 2015 for a total of $131,793. The other was related to 2015 plant and the charges and refunds were not related to AEP Ohio. While the Company understands the recommendation to adjust the year in which the credit relates, the value is immaterial on the carrying charge calculation for restatement. That being said, the Company received the credits in September 2015 and they have been included as a reduction to capital.

AEP-Ohio Status Response:

The Company has not implemented any of the recommendations from the Blue Ridge 2015 audit report as the Commission has not issued an order.

Blue Ridge Comments:

The credits were incorporated as a reduction to capital and should continue to be credited to the DIR as a reduction to capital going forward.

Recommendation 2: Blue Ridge recommended the Company provide a reconciliation in future filings comparing the amount of plant recovered in ESRR and gridSMART riders with the amount shown excluded within the DIR.

AEP-Ohio Initial Comment:

The Company disagrees with Blue Ridge's audit recommendation. The Company provides the net book value of the entire distribution capital as well as the net book value associated with the ESRR and gridSMART Phase I assets. The Phase I assets will be moved into the DIR and moot going forward; however, the Phase II assets will be excluded from the DIR and included for recovery in the Phase II rider. The timing of the filings do not matter. The Net Book Value removed from the DIR for the ESRR can already be tied to the plant collected in the ESRR as filed in the ESRR annual updates. Schedule 1 of the ESRR filings show the

[5] Case No. 16-0021-EL-RDR, Ohio Power Company Initial Comments, filed May 15, 2017.
[6] AEP Ohio's response to 2016 Data Request 1-008.

incremental plant balances that tie to the data provided in each quarterly DIR update. The Company will provide the Phase II assets in the DIR workpapers like it did the Phase I assets where the values can be verified, timing is not an issue. The current schedules are transparent and provide the detail needed.

If Blue Ridge was referring to the timing of the Phase I assets for recovery through the Phase I rider versus through the DIR, the Company has already filed its final Phase I rider and in that filing stated that it would stop removing the Phase I assets from the DIR beginning with April, 2017. The auditor, Staff or the Commission will see this change in the second quarterly filing of the DIR as that will be transparent on the schedule. In addition, the Phase II filing made by the Company shows the capital carrying costs for the Phase I assets ends in March 2017, and the capital carrying costs for these assets beginning April, 2017 will be collected through the DIR. There is no timing issue.

<u>AEP-Ohio Status Response:</u>

The Company has not implemented any of the recommendations from the Blue Ridge 2015 audit report as the Commission has not issued an order.

<u>Blue Ridge Comments</u>:

The Company's DIR filing includes a section from the ESRR filing that allows for a review of the cumulative capital spent on vegetation management to the Incremental Vegetation net book value. The Company's DIR filing also includes a workpaper showing the net book value of the gridSMART assets. The gridSMART Phase I rider was based on capital dollars spent, not net book value, so there is no net book value comparison, and the Company was unable to reconcile Net Book Value. The Company implemented a process that showed the amount of capital spent by work order for the Phase I project and compared that to the work orders included in the gridSMART net book value calculation in order to verify that all workorders were properly coded in the owned asset system and the assets associated with the capital being recovered through the Phase I rider were not also being recovered through the DIR.[7] Phase II of gridSMART will be implemented using a net book value calculation, which is different from the way it was done in Phase I.[8] The Company has complied for the ESRR. After the gridSMART I assets are transferred into the DIR, many of the difficulties associated with reconciling the DIR to the gridSMART rider should be resolved.

Recommendation 3: Blue Ridge recommended the Company provide jurisdictional allocations and accrual rates not only by account, as has been done, but also by subaccount.

<u>AEP-Ohio Initial Comment</u>:

The Company has fulfilled this request. There are no subaccounts, only 370.16, in which the Company shows on the schedule. The Company has worked with Staff to verify that it appropriately implemented the recommendations the staff made and Commission approved in the ESP III proceeding, Case No. 13-2385-EL-SSO.

[7] AEP Ohio's response to 2016 Data Request 8-008.
[8] AEP Ohio's response to 2016 Data Request 8-008.

Blue Ridge Comments:

The DIR under review in this proceeding includes the recommended information. No further work is needed.

Recommendation 4: Blue Ridge recommended, if a Lotus Notes® database is going to be used by management to approve projects, a form be attached to the project documentation to support the approval, providing an audit trail.

AEP-Ohio Initial Comment:

The Company no longer uses the Lotus Notes database for approvals.

Blue Ridge Comments:

Blue Ridge followed up on the Company's change in its process to document project approvals. The Company stated that the change from Lotus Notes to a PeopleSoft-based approval system was fully implemented in April 2014. During the conversion from Lotus Notes to PeopleSoft in 2014, some management approval signatures and/or dates were not carried over to new PeopleSoft database. This failure was attributed to the conversion of the systems. The current PeopleSoft system does incorporate approvals as defined in the Improvement Requisition Policy & Procedure.[9] No further work is required.

Recommendation 5: Blue Ridge recommended that the Company be required to provide the Commission information on the work orders in the sample selection that are greater than 15% over budget. That information should provide the detailed reason the work order was over budget. If a change order or estimate revision was initiated that increased the original estimate, the Company should provide that change documentation along with all necessary management approvals.

AEP-Ohio Initial Comment:

The Company followed up with Blue Ridge on the following recommendations by supplementing responses. There was misunderstanding in the audit questions and responses as it related to work order testing and budget versus actuals for each work order. The Blue Ridge audit report, on page 37, describes the budgeting process of the Company, correctly stating "The Company does not approve individual work orders. Most distribution work funding is approved at a program or higher level." Blue Ridge's recommendation is summarized on the audit report page 38 stating that "Blue Ridge asked the Company twice to provide budget and actual costs with explanations for variances of plus or minus 15%. The Company provided variance data on only 9 of 51 work orders in the sample when responded to the first request and no additional variance data on work orders in the second request." The Company did not provide the data per workorder as the Company does not budget to work orders as Blue Ridge noted in its report. The Company subsequently noticed that it inadvertently had not provided the necessary backup for the project in which one workorder rolled up to and supplemented that response to provide the information.

[9] AEP Ohio's response to 2016 Data Request 5-003.

Blue Ridge Comments:

Based on conversations with the Company during the current audit and the documentation provided for work order testing, the Company provided the documentation necessary for full evaluation, starting with the basic work order through the hierarchy of the project and ultimately to the program, if required.[10] Blue Ridge considers this issue resolved.

Recommendation 6: Blue Ridge recommended that work order costs associated with cost elements 141, 145, 154, and 155 be removed from the DIR. These costs, in Blue Ridge's opinion, are not payroll, payroll related, or an appropriate overhead cost that benefits the project(s).

AEP-Ohio Initial Comment:

The Company disagrees with Blue Ridge's recommendation. Blue Ridge notes in their audit report the Company's response to Data Request BR-INT-7-024 and then follows that by their recommendation. The Company stated that these cost components represent a portion of the Company's actual cost of labor. The charges listed are part of the Company's competitive compensation plan and in totality make up the total compensation package. These cost components are components of the reasonable market competitive compensation provided to AEP employees that benefits customers by enabling the Company to attract, retain, and motivate the employees needed to efficiently and effectively provide electric service to its customers. AEP compares its compensation plans to market plans in order to maintain competitiveness as an employer. The particular cost components are included for short term incentive compensation plans as well as long-term incentive compensation plans that allow employees at certain levels restricted stock and stock based compensation. The market based compensation includes base salary plus short term incentive for the total cash compensation. Additional compensation packages include base salary plus short term incentive for the total cash compensation and long-term incentive for the total compensation. In the development of the Staff reports prepared in Case Numbers 11-351-EL-AIR and 11-352-EL-AIR, the Staff specifically recognized this and incorporated incentives into their labor build up. In the stipulation of this case, the Staff reports were accepted as the basis of the Company's base distribution rates, so removing these cost components would be inappropriate and create a disconnect in cost recovery between base rates labor and the labor incorporated in capitalized projects.

Blue Ridge Comments:

Blue Ridge reviewed Staff's reply comment and recommendation to the Commission. Staff stated, "It is Staff's policy, however, to remove these types of labor costs. As such, Staff remains unpersuaded that these cost elements are appropriate for recovery as they have been incorporated by AEP Ohio in the DIR filings. AEP Ohio states in its comments that Staff specifically recognized these costs and incorporated them into its labor build up in the last rate case. AEP Ohio should provide actual evidence that these costs were authorized by the Commission."[11]

[10] AEP Ohio's response to 2016 Data Request 3-001, Attachments 2–7.
[11] Case No. 16-021-EL-RDR, Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio, June 5, 2017, page 4.

In the sample reviewed during the current audit, Blue Ridge found $138,511 charged to cost codes 141, 143, 145, 154, and 155. Approximately 97% was charged to cost code 141 (Incentive accrual department level). These costs, extrapolated to the full population of workorders, total approximately $353,200. Blue Ridge extrapolated the finding to the increase in net distribution plant since August 31, 2010, and estimates net distribution plant could be overstated by approximately $1.7 million. Until the Company can provide actual evidence that these costs were authorized by the Commission, Blue Ridge continues to recommend that the work order costs associated with cost elements 141, 145, 154, and 155 be removed from the DIR. In addition, cost code 143 (Other lump sum payments) should be removed from the DIR. These cost elements include costs that, in Blue Ridge's opinion, are not payroll, payroll related, or an appropriate overhead cost that benefits the project(s).[12] [13]

Recommendation 7: Blue Ridge recommended, in regard to work order 7900299 involving $669,609 for meter purchase from an affiliate, the Company demonstrate to the Commission that the purchase of meters from AEP affiliates represents the lowest cost alternative to the Company.

Recommendation 8: Blue Ridge recommends, in regard to work order 7900299 involving 4955 purchased meters for a total cost of $5,924,249, the Company provide to the Commission a comparison of the actual meter costs (without the capitalized labor or other installation costs) with other similar meter type costs, supporting the fact that this purchase was in line with other similar purchases.

AEP-Ohio Initial Comment:

The Company will work with the Staff on this recommendation. While the Company understands that this recommendation is around certain 2015 transactions, it is the Company's position that the Commission is aware of the process and benefits of the Company implementing the affiliated transaction agreement. In past cases, notably the gridSMART Phase I rollout of AMI meters, the Company provided benefits to the project by utilizing the affiliated transaction agreement to sell to other operating companies at Net Book Value the meters removed throughout the territory. These transactions allowed for a reduction in the cost of the overall program by selling the meters at their Net Book Value, decreasing the loss on removal of meters flowed through the Phase I rider.

Staff's Recommendation to the Commission:

> AEP Ohio's comments to this recommendation are not responsive. From discussions between AEP Ohio and Staff, AEP Ohio believes a miscommunication between it and Blue Ridge has occurred regarding the data it provided. Staff recommends that the Commission require AEP Ohio to provide the information sought in the recommendation. Staff would note that, although AEP Ohio may be able to clear up the per unit price of the meters, the other aspect of Blue Ridge's recommendation is

[12] WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix.
[13] WP AEP-Ohio – Extrapolated Incentive Comp Cost Codes-2016.

for AEP Ohio to demonstrate that the cost of these meters align with other similar purchases. AEP Ohio should include this cost-alignment demonstration it is response.[14]

Company's Reply Comments:

In its initial response to the data request, AEP Ohio provided the affiliated Company purchase agreement which included the prudency of the purchase. Nonetheless, in order to further validate the benefit of the agreement, the Company is providing that the savings to AE Ohio customers for the affiliate meter purchases for 2015 were approximately $64,000. These savings were calculated by adding the accumulated depreciation of all meters purchased by AEP Ohio as compared to the total cost if AEP Ohio had purchased the meters.

Additional data is being provided by AEP Ohio in reference to the Staff's recommendation that the Commission adopt the recommendations of Blue Ridge. In particular, Blue Ridge audit recommendation number eight included proving that the cost of the meters for Work order 7900299 was in line with the cost of other meters. In the response, the Company provided the cost per meter for three work orders, including the work order in question in order to prove that the costs were in line with other meter purchases. However, Blue Ridge attests that the Company did not provide the data necessary. In order to provide the appropriate detail, the Company is submitting the information through its reply comments.

Indeed, the amount of the work order in question would show that the average cost per unit for work order 7900299 is $321.86. This average cost was based on all purchases and units in 2015. For purposes of these reply comments, the Company randomly sampled two months on invoices, January and July, 2015 in order to provide useful information to assist the Commission in its determination of the Company's prudent purchases. There were 91 invoices associated with 2015 meter purchases for this particular work order. In order to maintain confidential pricing of our vendors, the Company will provide a summary of the items purchased as well as the purchase price. The invoices can be reviewed at the request of Staff or Blue Ridge if the Commission determines greater detail is needed.

It is important to note that there are meter transformers that are capitalized to the meter account as well. It is also important to note that different types of meters have different costs. For instance, meters capable of registering kWh and kW are more expensive than traditional meters without this capability. A sample of the invoices will show that the more expensive meters capable of registering kWh and kW cost approximately $227. Other less sophisticated AMR meters cost between

[14] Case No. 16-021-EL-RDR, Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio, June 5, 2017, page 4.

$33 and $35. However, the invoices selected included six invoices for meter transformers. These transformers are like the meters in that the more sophisticated transformers are more expensive. As an example, of the invoices selected, the more sophisticated transformers had a unit cost of $845, $960 and $1,515 per unit. Other less sophisticated meter transformers cost $69 per unit.

The Company asserts that its policy for procurement is reasonable and that Blue Ridge is aware of the procurement process of the utility and that the determination of the processes reasonableness alone is sufficient to conclude that the costs paid by the Company are in line with other meters purchased. A review of the data responses show that the Company did in fact answer the question as Blue Ridge proposed. Although the Company provided the average of three work orders in order to show how the average meter costs of all meters purchased compared, the data included provided the actual cost of the purchases as well as the number of units for each work order separately and the information could be concluded in the discovery response as answered by the Company.[15]

Blue Ridge Comments:

Blue Ridge sought additional information from the Company during this audit to validate that the purchase of meters from AEP affiliates represents the lowest cost alternative to the Company. The Company provided a list of the meters purchased from each affiliate along with the net book value cost. Also provided were a comparison of those meters purchased to what the same meters would cost on the open market. The cost comparison shows that purchases from affiliates at net book value are less than the cost to buy meters in the marketplace. All purchases were from regulated utilities.[16] Blue Ridge found that the transferred cost of meters acquired from affiliates is less than the amount the Company would have paid if those meters had been purchased from a third-party vendor. Blude Ridge considers this issue resolved.

Recommendation 9: Blue Ridge recommended the Company continue to monitor inactive work orders that appear on the inactive work order report and strive to resolve outstanding issues within a reasonable time frame of six months.

AEP-Ohio Initial Comment:

The Company agrees with this recommendation to the extent possible. However, work orders can be inactive for various reasons, including awaiting work by third parties, awaiting billings that are not submitted from contractors, rescheduling of projects, etc. While these reasons can be outside the Company's control, there is a SOX procedure for quarterly review of inactive workorders, including sign off by management.

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[15] Case No. 16-0021-EL-RDR, Reply Comments of Ohio Power Company, June 5, 2017, pages 10–12.
[16] AEP Ohio's response to 2016 Data Request 8-007, Attachment 1.

Blue Ridge Comments:

Blue Ridge agrees with the Company's explanation that some inactive work orders are outside the Company's control. An example is work pending customer approval or action on the part of the customer or municipality.

Blue Ridge reviewed the inactive work orders for the fourth quarter of 2016. The report contained 522 work orders, and they were inactive from 13 to 138 months.[17] Of the 522 work orders, 114 were completed and in-service, totaling approximately $2.747 million, and 59 had been cancelled, totaling approximately $139,700. Those work orders will be charged to expense and do not impact the DIR. An additional 26 work orders, totaling $49,600, are waiting on the customer. All the work orders have been reviewed, and the Company is following the process to monitor inactive work orders, and that process is not unreasonable.[18] Blue Ridge is satisfied with the Company's explanation and actions.

Recommendation 10: Blue Ridge recommends the Company adhere to its stated policy to not hold work orders open to collect additional charges past 90 days.

AEP-Ohio Initial Comment:

The Company agrees with this recommendation.

Blue Ridge Comments:

Blue Ridge's review in this year's audit included a review of whether work orders had been held open past 90 days to collect additional charges. Blue Ridge found all work orders that were not blankets/programs/projects were closed within the 90-day window.[19] Blue Ridge considers this issue resolved.

[17] AEP Ohio's response to 2016 Data Request 1-044, Attachment 2.
[18] AEP Ohio's response to 2016 Data Request 1-047.
[19] WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix.

FINDINGS AND RECOMMENDATIONS

PROCESSES AND CONTROLS

The compliance audit of the AEP Ohio DIR does not call for a regulatory management audit (i.e., a diagnostic examination purposed to assess the effectiveness and efficiency of operation of a specific regulated utility). However, while Blue Ridge did not perform a management audit, we did review AEP Ohio's processes and controls to ensure that they were sufficient so as not to adversely affect the costs in the DIR. Based on the documents reviewed, Blue Ridge was able to update its understanding of the Company's processes and controls that impact each of the plant balances and expense categories within the DIR. Blue Ridge found that AEP Ohio's cost controls were adequate and not unreasonable. The following is a summary of the areas Blue Ridge reviewed.

DIR PREPARATION

Blue Ridge had obtained an understanding of how the DIR is prepared from AEP Ohio's description of the process: "The Rider is based on the FERC Form 3Q Net Book Value for Distribution Plant. The Net Book Value of gridSMART assets is removed from the rider because recovery of those assets is achieved through the gridSMART rider. The Net Book Value of gridSMART assets is obtained through a query of the owned asset system provided by property accounting. The capital dollars spent for vegetation management are also removed from the rider. These values are obtained from the distribution operations system by [the AEP Ohio regulatory department] and removed from Rider DIR because the recovery of incremental capital dollars for vegetation management [is] recovered through the Enhanced Service Reliability Rider. ADIT is removed from rider DIR per the order in Case Nos. 11-346-EL-SSO and 13-2385-EL-SSO. ADIT values are reflected on the balance sheet for the distribution function only in account 2821001[,] which is ADIT for utility property. $62,344,000 is then added to reflect the credit provided to rate payers as approved in Case No. 11-351-EL-AIR. In addition, the over/under recovery balance from the previous quarter is added or subtracted to get to the fully adjusted revenue requirement. Once the fully adjusted Revenue Requirement is calculated, AEP Ohio Regulatory provides the base distribution revenue in order to complete the rate design. This revenue is obtained from a query from the customer billing system that can be demonstrated during an onsite audit."[20]

This process is the same as used by the Company for the rider's development in previous years.[21] The Company also stated that no changes were made to the process during the current audit year (2016).[22]

POLICIES AND PROCEDURES

During last year's audit of the 2015 DIR, Blue Ridge requested and received the policies and procedures for the development of the Rider DIR.[23] In its response, the Company provided its management report that was included in Case No. 13-419-EL-RDR. The report contained pertinent policy/procedural elements as follows:

1. Accounting (beginning on page 1)
2. Financial Reporting (beginning on page 52)

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[20] AEP Ohio's response to 2015 Data Request 1-003.
[21] AEP Ohio's response to 2015 Data Request 1-005.
[22] AEP Ohio's response to 2016 Data Request 1-003.
[23] AEP Ohio's response to 2015 Data Request 1-010, Attachment 1.

3. Supply Chain (beginning on page 253)
4. Audit Services (beginning on page 267)
5. Risk Management (beginning on page 273)

The following discussion presents a general overview of these elements.[24]

Accounting

The section of the Company's management report containing accounting policy provided information regarding description of impetus and method for accounting-issue modifications. The senior vice president, controller, and chief accounting officer is responsible for setting overall accounting policy affecting the operating companies, thus maintaining a higher degree of similarity among the operating companies for similar accounting transactions. Of course, in some circumstances, compliance with jurisdictional and local requirements may demand specific differences.

Each department determines goals and objectives on an annual basis. These departmental goals and objectives relate to the overall corporate goals and objectives. Criteria used in determining goals and objectives include available resources, benefits to be derived, community presence, historical precedent, and trends as well as future projections, regulatory requirements, and contribution to overall corporate goals and objectives.

Besides the Policy and Goal Setting subsection just discussed, each major policy section also contains the following sub-sections:

a. Strategic and Long-Range Planning
b. Organization Structure
c. Decision-Making
d. Ring-Fencing
e. Controlling Process
f. Internal and External Communications

Specific accounting procedures presented include Fixed Asset Policy and Conventions, Financial Reporting Policies and Conventions, Regulatory Accounting Policy and Conventions, Treasury Policies and Conventions, Revenue and Receivables Policies and Conventions, Share-based Payment Policy and Conventions, Intangibles – Goodwill and Other Policy and Conventions, Pension and Postretirement Benefit Plan Policies and Conventions, Tax Accounting Policy and Conventions, and Inventory.

Financial Reporting

Within the Accounting section of the management report, but separately gathered as Exhibit 4 to that section, is the discussion of Process Overview of the Financial Reporting Cycle. Within the financial reporting cycle section, the Company details its processes and sub-processes:

a. Disclosures
    - Summary Obligation Information
    - Quantitative and Qualitative Disclosures about Risk Management Activities
    - Variable Interest Entities
    - Earnings Per Share

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[24] The information discussed under all five points of this general overview of policies and procedures comes from AEP Ohio's response to 2015 Data Request 1-010, Attachment 1.

- New Accounting Pronouncements, Cumulative Effect of Accounting Changes and Extraordinary Items
- Goodwill and Other Intangible Assets
- Rate Matters
- Effects of Regulation
- Commitments and Contingencies
- Guarantees
- Acquisitions, Dispositions, Discontinued Operations, Impairments and Assets Held for Sale
- Benefit Plans
- Business Segments
- Derivatives and Hedging
- Fair Value Measurements of Financial Assets and Liabilities
- Fair Value Measurements of Investment Securities
- Fair Value Measurements of Long-term Debt
- Income Taxes
- Leases
- Financing Activities – Common Stock and Preferred Stock
- Financing Activities – Long-term Debt
- Financing Activities – Money Pool
- Financing Activities – Sale of Receivables
- Financing Activities – Short-term Debt
- Stock-Based Compensation
- Related Parties
- Property, Plant and Equipment
- Asset Retirement Obligations
- Jointly-Owned Electric Utility Plant[25]
- Unaudited Quarterly Financial Information

b. Financial Statements
  - Income Statement for 10K/10Q Presentation
  - Equity Statement for 10K/10Q Presentation
  - Balance Sheet for 10K/10Q Presentation
  - Cash Flow Statement for 10K/10Q Presentation

Several pages of Work Program Review forms follow. The Fair Value Measurement Policy and the Accounting Policy Manual Hedging Activities are provided. Finally, the Revenue Netting Policy is recorded.

Supply Chain

AEP Ohio does not issue its own Supply Chain policies but rather supports the policies within the overall AEP system of operating and affiliate companies. Departmental progress toward achieving operational objectives is reported to senior management on a quarterly basis. Objectives are communicated in both written and oral fashion. These objectives are in view during performance reviews, staff meetings, and other ad-hoc performance coaching sessions.

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[25] The Disclosure process for Jointly-Owned Electric Utility Plant appears in the Management Report twice—first on page 123 and then repeated on page 124.

The responsibilities for the departments within Supply Chain and Fleet Operations include the following:

a. Supply Chain & Fleet Operations – AEP Ohio
    - Supply Chain Inventory Operations
    - Fleet Services
b. Supply Chain Operations – Regional Distribution Centers
    - Supply Chain Regional Distribution Center Operations – Canton, Ohio
c. Supply Chain Operations – Generation
    - Supply Chain Inventory Operations – Indiana Michigan Power, Cardinal Plant, AEP Ohio South Region
    - Supply Chain Inventory Operations – AEP Ohio North Region & Gas Units
    - Asset Recovery
    - Catalog Services
d. Supply Chain & Fleet Operations – Inventory Management
    - Supply Chain & Fleet Technical Reporting and Analysis
    - Distribution Inventory Management
    - Transmission Inventory Management
    - Fleet Services Analysis Support

Audit Services

AEP has an internal audit function with approximately forty in-house personnel. The overall goal is to function as an independent appraisal activity for AEP by helping management and the board of directors control business risks within acceptable levels. The Audit Services Charter lists the scope of the department to include the following:

a. Assisting the Audit Committee in carrying out their duties and responsibilities
b. Assisting the Audit Committee in carrying out their duties and responsibilities
c. Appraising the effectiveness and application of internal control over financial reporting, compliance with laws, and operations
d. Coordinating and managing the Sarbanes-Oxley 302 and 404 internal control reporting processes
e. Evaluating sufficiency of and adherence to Company plans, policies and procedures and compliance with the requirements of regulatory bodies
f. Ascertaining the adequacy of controls for safeguarding Company assets and when appropriate, verifying the existence of assets
g. Appraising the quality of performance in carrying out assigned responsibilities
h. Coordinating audit planning and scheduling activities with the independent auditor
i. Conducting special examinations at the request of management or the Board of Directors

The strategy employed by Audit Services includes conducting a risk assessment / audit prioritization process each year to create an annual audit plan. Input to the plan includes management interviews; strategic plan review; enterprise risk management reports review; budgets and forecasts review; prior audit results; trade, regulatory, and professional literature review; news articles; external auditor interviews; and most current fraud risk assessment reference.

Risk Management

Risk & Strategic Initiatives holds responsibility for monitoring compliance with the risk management policies, procedures, and strategies as established by the policies for credit risk, AEP Commercial Operations market risk, and enterprise risk management. Specifically, the following list specifies major areas of responsibility:

a. Manage AEP's insurance programs
b. Captive insurance oversight
c. Hazard risk analysis
d. Claims management
e. Hazard risk control
f. Evaluating and reporting AEP's risks on an enterprise basis
g. Market risk oversight
h. Credit risk management
i. Pension and benefit plan investment oversight
j. Strategic initiatives basis

CAPITALIZATION POLICIES

In the 2012 audit, Blue Ridge had asked for the policies that related to the capitalization process. The Company provided six policies/procedures of process documentation.[26] Blue Ridge reviewed these documents to reacquaint itself with the policies.

1. Acquiring Fixed Assets Authorization—The purpose of this policy is to outline the Capital Improvement Requisition Interface between PeopleSoft Projects and PowerPlant.
2. Fixed Asset Closing (Work Order Closing)—This document details the process of completing the acquisition of Fixed Assets.
3. Fixed Asset Completion—This flowchart presented the process path for completion of work orders.
4. Depreciating Owned Assets Process—The purpose of this process documentation is to outline the depreciation process for owned assets.
5. Disposition of Fixed Assets—The purpose of this procedure is to outline the fixed asset disposition process.
6. Fixed Assets Reporting Process—The purpose of this process documentation is to outline the fixed asset reporting process.

Blue Ridge also requested and received a listing of changes that have occurred to the capitalization policies since the 2012 audit:[27]

1. September 2012: Established a retirement unit for the application of epoxy sealant to an underground vault which increases the lifespan of the underground vault by 15 to 20 years and also protects the environment from oil spills.
2. May 2013: Established a retirement unit for a Line Voltage Monitor which strategically monitors the distribution voltage levels typically in coordination with Volt Var Optimization (VVO) applications and to provide data to the Distribution SCADA system. This was new technology to AEP.

[26] AEP Ohio's response to 2012 Data Request 1-008, Attachments 1 through 6.
[27] AEP Ohio's response to 2015 Data Request 1-011, Attachment 1.

3. May 2013: Established a retirement unit for a Voltage Regulator Control which controls distribution voltage regulators locally, through Distribution SCADA and in coordination with Volt Var Optimization (VVO) applications.
4. May 2014: Provided guidance on time reporting for safety meetings. Based on the Company's review, they determined that it was reasonable to allocate safety meeting time between capital and O&M. Previously only jobsite safety briefings qualified for capitalization.
5. December 2014: Established retirement units for a High Thermal Event Protection System (HTES) and a HTES Battery Supply. The HTES monitors the condition of network equipment in indoor building vaults and will isolate and de-energize the equipment in the event of a failure. This was a new use of technology at AEP.
6. June 2015: Established retirement units for a Network Data Concentrator, Network Data Hub, and a Network Sensor. This equipment is part of the network monitoring solution being implemented across the AEP System. This was a new use of technology at AEP.

During this year's 2016 DIR audit, Blue Ridge requested information on any changes to the policies and procedures as specified above. The Company stated that the only change made was to the capitalization policy by which a retirement unit for Energy Control Devices and Displays was established. This equipment works in conjunction with smart meters and can be used to provide the customer and AEP with real time information regarding energy costs and use. The equipment is new-use technology at AEP.[28] Although this equipment attaches to the meter, it is purchased separately and can be replaced separately, qualifying it as a stand-alone retirement unit. Blue Ridge recommends that the Company highlight and quantify this and any other changes to the capitalization policy in the DIR filing preceding the implementation of the change.

The Company also provided, on request, the document for level of signature authority in service during 2016.[29]

Recommendation #4 of last year's DIR audit stated that if a Lotus Notes® database was to be used by management to approve projects, a form should be attached to the project documentation to support the approval, providing an audit trail. The Company responded to that recommendation by stating that it no longer uses the Lotus Notes® database for approvals. Upon follow-up to this change, Blue Ridge discovered that the Company did not update the Distribution Business Rules for Authorizing Capital Projects in regard to this change. Rather, a new Improvement Requisition Policy and Procedures document was issued in June of 2016 that addresses Capital Projects. Additionally, the AEP Authorization Policy was updated in 2015. The Company stated that the new Improvement Requisition Policy and Procedures supersedes the Distribution Business Rules for Authorizing Capital Projects.[30] Blue Ridge recommends that if the Distribution Business Rules for Authorizing Capital Projects is still in use in its current form, it should make mention within that document of the superseding status of the 2016 new Improvement Requisition Policy and Procedures.

Blue Ridge determined that the Company's policies and procedures specified above and in effect for 2016 were adequate and not unreasonable.

[28] AEP Ohio's response to 2016 Data Request 1-011, including Attachment 1.
[29] AEP Ohio's response to 2016 Data Request 1-013, including Attachments 1 and 2.
[30] AEP Ohio's response to 2016 Data Request 5-003, including Attachments 1 and 2.

RIDER DIR INTERNAL AUDIT AND SOX AUDIT

Blue Ridge requested a list of internal audits performed for 2016. The Company responded that it had no DIR internal audits performed for 2016.[31] In a follow-up request, Blue Ridge made clear that its interest went beyond internal audits directly on the DIR to include internal audits which could affect the DIR. Feeder systems that charge Distribution work orders, including those affecting Payroll, M&S, Transportation, overheads, and contractors, can have costs closing to plant in service which become part of the DIR. In consideration of those source costs, Blue Ridge again asked for a list of internal audits for any systems that feed CWIP in order to review their bearing on the DIR. In response, the Company provided a list of five internal audits, including scope, objectives, and dates. From this list, Blue Ridge selected three to examine in greater depth, requesting the summary findings and recommendations resulting from those audits. Upon examination, all three were found to be well-controlled.[32]

1. Cost Capitalization Data Analytics Review (November 2016)
2. Canton Allocations—Labor, Compatible Units, Stores, Intercompany, and Building/Telephone (May 2016)
3. Service Company Cost Allocations Review (July 2016)

SOX controls cover payroll processing, account reconciliations, appropriate accruals, third-party controls, accurate employee master file, proper liability estimates, accurate valuation and recordation for pensions and OPEB, retirement calculations, appropriate user access, and time approval. These control objectives—all of which are identical to the objectives reviewed in the 2015 audit—were retested in 2016, and all controls passed in 2016.[33]

CONCLUSION

From the documents reviewed, Blue Ridge was able to obtain an understanding of the Company's processes and controls that affect the DIR. Furthermore, we were satisfied with actions taken with regard to internal audits and SOX-compliance testing. Blue Ridge concluded AEP Ohio's controls were adequate and not unreasonable.

VARIANCE ANALYSIS

Blue Ridge's variance analysis focused on identifying, quantifying, and explaining any significant net plant increases within the individual plant accounts. In its plan for analysis, Blue Ridge anticipated requesting from the Company explanations for any significant changes. Based on its investigative and analytic evaluation of the account changes and the Company's explanations, Blue Ridge would then arrive at its conclusions regarding the reasonableness of those changes.

Blue Ridge concentrated its efforts on four areas of account balance comparison in pursuing determination of variance reasonableness:

1. **Beginning DIR Balance to Prior Year FERC Form 1:** Beginning of the year 2016 DIR filing compared to the end of the prior year (2015) FERC Form 1 filing by account
2. **2016 DIR to 2016 FERC Form 1:** 2016 DIR quarterly filings compared to 2016 FERC Form 1 Annual Report and each quarterly Supplemental Form 3-Q

[31] AEP Ohio's response to 2016 Data Request 1-014.
[32] AEP Ohio's response to 2016 Data Request 6-001, including Attachments 1, 2, and 3.
[33] AEP Ohio's response to 2016 Data Request 1-015, including Attachment 1.

3. **2016 DIR Filings Period to Period:** 2016 DIR quarterly filings, comparing one quarter to the next and comparing the 4th quarter to the 2015 DIR 4th quarter
4. **2016 Additions, Retirements, and Transfers/Adjustments:** 2016 Distribution Plant beginning balances by account compared to the 2016 ending balances for those accounts, while evaluating additions, retirements, and transfers/adjustments over the course of the year

Analysis: Beginning DIR to Prior FERC Form 1

Assurance that the 2016 DIR calculations began from account balances consistent with the FERC Form 1 reporting is necessary. This comparison was performed in last year's Rider DIR audit using the ending account balances of the 2015 Rider DIR in comparison with the 2015 FERC Form 1. Blue Ridge, therefore, reviewed that comparison in association with documentation provided in the current audit for beginning balances and concluded that balances matched, giving reasonable assurance that the 2016 DIR calculations began from accurate account amounts.

Analysis: 2016 DIR to 2016 FERC Form 1

Since the 2016 DIR calculations for each quarter are based on the Company's distribution account balances, Blue Ridge compared the account balances provided in each quarter's DIR filings[34] to the 2016 FERC Form 1 quarterly Supplemental Form 3-Qs.[35] For the first three quarters, account balances matched. For the fourth quarter all accounts matched except account 362—Station Equipment. The Company explained that the difference was due to a misclassification between utility account 36200 (Distribution Plant) and utility account 35300 (Transmission Plant). This transaction should have been in Transmission account 35300, but was approved with the incorrect 36200 account. The DIR filing reflects the adjustment made in April 2017 to correct the error. The Company's filing did not include an explanation of why the DIR filing was different from the FERC Form 1 filing. While the Company provided the above explanation for the difference during discovery,[36] the Company is not in compliance with the Commission's Order to provide the reconciliation within the DIR filing. Blue Ridge recommends that the Company provide the reconciliation to the FERC Form 1 within the DIR filings as ordered by the Commission.

Taking into account the explanation of the misclassification, the results of the comparison provide reasonable assurance that the account amounts used in calculations were accurate.

Analysis: 2015 DIR Filings Period to Period

One indicator assisting in providing assurance of consistent treatment of distribution capital assets can be the size of the changes to the distribution accounts from quarter to quarter and year to year. To satisfy the concern regarding consistent treatment of distribution capital assets in regard to size of account balance change from one period to the next, Blue Ridge identifies any significant variances and then requests explanations for those variances from the Company. Blue Ridge performed a quarter-to-quarter comparison of the 2016 DIR quarterly filings[37] (including the first quarter comparison to the 2015 fourth quarter filing) and found that none of the account variances reached a level of concern. Blue Ridge also compared the 2016 DIR fourth quarter filing

[34] AEP Ohio's response to 2016 Data Request 1-002, Attachments 1–4.
[35] AEP Ohio's response to 2016 Data Request 1-007, Attachments 1–4.
[36] AEP Ohio's response to 2016 Data Request 1-007.
[37] AEP Ohio's response to 2016 Data Request 1-002, Attachments 1–4.

to the 2015 fourth quarter filing and found that the changes on an annual basis also did not rise to a level of concern.

Analysis: 2016 Additions, Retirements, and Transfers/Adjustments

To be assured of appropriate 2016 distribution account changes regarding additions, retirements, and transfers/adjustments, Blue Ridge requested and received the 2016 beginning and ending period balances by primary plant account for additions, retirements, transfers, and adjustments.[38]

Table 1: AEP 2016 Distribution Plant Additions, Retirements, and Transfers/Adjustments

Utility Account	01/01/2016 balance	additions	retirements	trans_adj	12/31/2016 balance
36000 - Land Total	16,746,209.35	38,424.93	-	262,942.15	17,047,576.43
36010 - Land Rights Total	42,758,936.72	1,825,470.31	-	-	44,584,407.03
36100 - Structures and Improvements Total	20,292,628.53	282,851.38	(23,662.37)	1,295.56	20,553,113.10
36200 - Station Equipment Total	638,999,564.10	33,816,532.88	(3,668,217.30)	-	669,147,879.68
36300 - Storage Battery Equipment Total	5,069,926.03	-	-	-	5,069,926.03
36400 - Poles, Towers and Fixtures Total	686,925,728.20	36,672,356.12	(10,174,643.26)	-	713,423,441.06
36500 - Overhead Conductors, Device Total	712,761,291.34	38,452,138.73	(12,858,334.01)	-	738,355,096.06
36600 - Underground Conduit Total	222,931,960.98	23,310,992.91	(89,715.42)	-	246,153,238.47
36700 - Undergrnd Conductors,Device Total	600,664,266.01	39,422,294.13	(7,621,908.13)	-	632,464,652.01
36800 - Line Transformers Total	735,085,625.99	35,608,967.23	(15,100,609.71)	-	755,593,983.51
36900 - Services Total	320,898,536.63	8,160,908.43	(2,983,124.74)	-	326,076,320.32
37000 - Meters Total	166,643,611.07	6,056,411.17	(2,436,175.06)	993,378.73	171,257,225.91
37016 - AMI Meters Total	19,863,795.01	2,224,749.69	(879,982.39)	(993,378.73)	20,215,183.58
37100 - Installs Customer Premises Total	54,612,000.78	2,440,324.00	(2,222,518.94)	-	54,829,805.84
37200 - Leased Prop Cust Premises Total	103,067.00	-	-	-	103,067.00
37300 - Street Lghtng & Signal Sys Total	39,718,084.06	1,227,224.59	(1,047,553.71)	-	39,897,754.94
	4,284,075,231.80	**229,539,646.50**	**(59,106,445.04)**	**264,237.71**	**4,454,772,670.97**

In reviewing the spreadsheet information provided, Blue Ridge's analysis focused on irregular items (e.g., large adjustments, positive retirement amounts, negative additions, larger additions for an account compared to retirements, and increases in additions for an account over the previous year). After reviewing the balances for the accounts within the period scope, Blue Ridge identified the following categories and specific account examples for which we requested explanation regarding the activity.[39]

1. Transfer/Adjustment to Account 360 – Land: Transfers/Adjustments: $262,942.15)

   AEP Response: Land was purchased on which to build a new distribution substation. At the time of purchase (March 2016), the county auditor recorded it correctly as owned by AEP Ohio Distribution. The work order provided to Land Management, however, was incorrectly set up for AEP Ohio Transmission Company. The error was discovered and a transfer was initiated to reflect the land's legal ownership. The Company supplied supporting documentation for the initial purchase and transfer.

2. Additions significantly larger than retirements

   a. Account 360: Additions $1,825,470 and Retirements $0

      AEP Response: Purchasing land will not automatically result in retirement of other tracts of land (as it would be more likely to do for equipment). Further, if land moves from active use to inactive use (for example, if a substation is closed and a new

[38] AEP Ohio's response to 2016 Data Request 1-016, Attachment 1.

[39] AEP Ohio's response to 2016 Data Requests 7-002 through 7-004 (including attachments).

substation built elsewhere), the land would be either sold or transferred to plant held for future use (FERC Account 105).

b. Account 362: Additions $33,816,532 and Retirements $3,668,217

AEP Response: For Account 362: Station Equipment, four conditions contributed to the additions being significantly larger than retirements: (1) several of the highest-cost work orders were for transformers purchased as spares and, therefore, did not have corresponding retirement units, (2) some of the station installations were new builds without associated retirements, (3) the retirements values were significantly lower than corresponding additions on some equipment because of the low book value of the retired equipment, and (4) the retirements for work order 42263333, Dennison Station Transformer replacement, were incorrectly booked to the installation work order. The related $145,000 of retirements will be reclassified to the proper work order.

The Company provided the 2016 work order listing of additions and retirements for account 362 confirming their explanations.

c. Account 366: Additions $23,310,992 and Retirements $89,715

AEP Response: The policy in prior decades of the 1960s, 1970s, and 1980s called for installation of underground conductor without conduit. Therefore, as replacements are performed, little to no actual conduit was replaced. The Company provided the listing of work orders for account 366 showing the additions and individual retirements as reflective of the fact.

d. Account 367: Additions $39,422,294 and Retirements $7,621,908

AEP Response: A large number of projects in account 367: Underground Conductors were new builds with no associated retirements. For those projects with retirements, much of the difference between additions and retirements are due to increases in cost of labor and materials in 2016 versus the costs during the years in which the retired conductor was installed. The Company provided the listing of 2016 work orders for account 367 confirming their explanations.

3. Addition increase for 2016 over 2015 regarding Account 366 – Underground Conduit: 2016 Additions $23,310,992 and 2015 Additions $17,978,245 (difference = $5,332,748; ~30%)

   AEP Response: The difference is due almost entirely to five work order credits in 2015, lowering the additions. Four projects included reimbursements in 2015 on work done in previous years. A fifth work order received credit for a reclassification of 2015 balances from account 366 to 367. Without these five work order credits, additions were consistent between years. The Company provided the 2015 and 2016 work order listings confirming the credit entries.

Conclusion

Based on Blue Ridge's review of variances in the Company account balances during the 2016 DIR year, no variances resulted in concerns for the proper calculation of DIR amounts. Blue Ridge does recommend that the Company follow through with the error discovered regarding the retirements for work order 42263333 and reclassify the associated $145,000 to the proper work order.

REVENUE REQUIREMENTS

OVERVIEW OF METHODOLOGY

In Case No. 11-346-EL-SSO et al., (*ESP 2 Case*) the Company requested a Distribution Investment Rider (DIR) that would allow carrying costs on incremental distribution plant to be recovered each year using a pre-tax weighted average cost of capital (WACC) and an O&M component. The DIR revenue requirement excluded recovery on plant included in prior base distribution rate cases and plant recovered in other riders.

The Commission approved the DIR (with modifications) as "an appropriate incentive to accelerate recovery of AEP Ohio's prudently incurred distribution investment costs." The Commission ordered that the DIR mechanism not include any gridSMART costs.[40] The gridSMART projects are separate from the DIR and are recovered through the gridSMART rider. The DIR also excludes capital dollars spent for vegetation management that are recovered through the Enhanced Service Reliability Rider (ESRR). Furthermore, the Commission ordered that the DIR mechanism be revised to account for accumulated deferred income tax (ADIT).[41]

The DIR is subject to an annual cap with allowances for over or under recovery. The rider is collected as a percentage of base distribution revenue.[42] It is updated quarterly based on the incremental increase in the net plant balance as shown on Form 3Q. The DIR was scheduled to end May 31, 2015.[43]

Case No. 13-2385-EL-SSO extended the DIR through May 2018 and incorporated several modifications. The modifications included approval of rate caps for 2015 through May 2018, a revision to the property tax calculation, and modifications to adopt six recommendations by Staff regarding detailed account information, jurisdictional allocations and accrual rates, reconciliation between functional ledgers and FERC-form filings, revenue collected by month in the DIR, highlighting and quantifying DIR capitalization policy, and the filing of an updated depreciation study by November 2016.[44]

In a Second Entry on Rehearing in Case No. 13-2385-EL-SSO, the Commission authorized revenue caps for the DIR to be set at $145 million for 2015 (including amounts previously authorized in the *ESP 2 Case*), $165 million for 2016, $185 million for 2017, and $86 million for January through May 2018.[45]

The Commission also reaffirmed the DIR is a percentage of customer base distribution charges.[46] The DIR percentages of base distribution at the end of 2015 and each quarter of 2016 are shown in the following table.

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[40] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 46.
[41] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 47.
[42] Case No. 11-346-EL-SSO, et al., Direct Testimony of Andrea E. Moore, page 13.
[43] Case No. 11-346-EL-SSO, et al., Direct Testimony of William A. Allen, page 10.
[44] Case No. 13-2385-EL-SSO, et al., Order dated February 25, 2015, pages 46-47.
[45] Case No. 13-2385-EL-SSO, et al., Second Entry on Rehearing dated May 28, 2015, page 24.
[46] Case No. 13-2385-EL-SSO, et al., Order dated February 25, 2015, page 46.

Table 2: Rider DIR - Percentage of Base Distribution Revenues by Quarter

Period	Percent of Base Distribution Revenues
End of 2015	28.15380%
1st Quarter 2016	29.13302%
2nd Quarter 2016	29.96506%
3rd Quarter 2016	28.98750%
4th Quarter 2016	29.77473%

REVISIONS TO DIR ORDERED IN CASE NO. 13-2385-EL-SSO

In Case No. 13-2385-EL-SSO, as part of the Commission's extension of the DIR, the Commission ordered several modifications to the DIR. These modifications included the adoption of six recommendations made by Staff, adoption of OCC's recommendation regarding property taxes, and the inclusion of gridSMART Phase 1 capital costs within the DIR.

Staff's Recommendations

The Commission adopted the following six recommendations made by Staff.[47] In the 2015 audit, the Company provided the status of each of these recommendations.

1. Detailed Account Information: AEP should file what plant in service is being recorded and recovered in the Enhanced Vegetation Rider, the gridSMART Phase II Rider, the Solar Rider, and any other rider which is recovering Distribution plant in service. AEP should provide this information by plant account and subaccount for each rider. Providing this information to the Commission is critical because it will allow Staff to ensure that no plant-in-service costs related to other riders are being recovered in the DIR.

   2015 Audit Status per Company: The Company stated that it has worked with Staff and implemented Staff's recommendations, beginning with the filing for September 2015 plant balances.[48]

   Blue Ridge's Comment: The Company stated that the riders for Enhanced Service Reliability and gridSMART were the only riders that included distribution plant.[49] The Company attached to each quarterly filing a summary of the distribution assets associated with the Company's gridSMART and vegetation management assets that are recovered through those riders. The gridSMART summary schedule included the plant account. However, the vegetation management schedule did not include the plant accounts. Blue Ridge recommends that the vegetation management schedule in the DIR include the plant accounts and subaccounts.

2. Jurisdictional Allocations and Accrual Rates: Require AEP to use the jurisdictional allocations and accrual rates for each account and subaccount that were approved in AEP's prior AIR case, subject to Staff's exception for gridSMART depreciation rates.

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[47] Case No. 13-2385-EL-SSO, Opinion and Order dated February 25, 2015, pages 46-47 and the Prefiled Testimony of Doris McCarter (Staff Exhibit 17, pages 5-7).
[48] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 30.
[49] AEP Ohio's response to 2016 Data Request 1-037.

2015 Audit Status per Company: The Company stated that it has worked with Staff and implemented Staff's recommendations, beginning with the filing for September 2015 plant balances.[50]

Blue Ridge's Comment: The Company included the jurisdictional allocations and accrual rates for each account and subaccount that were approved in AEP's prior AIR case, subject to Staff's exception for gridSMART depreciation rates. No additional work is required.

3. Reconciliation between Functional Ledgers and FERC-Form 1 Filings: In each DIR filing, AEP should include, for each account and subaccount, a full reconciliation between the functional ledger and FERC-form 1 filings as well as detailed workpapers showing the jurisdictional allocation, accrual rates, and reserve balances of each account and subaccount. AEP should be directed to provide this information, for any rider being used to collect costs recorded in the Distribution Plant Accounts, by rider and as a grand total. Commission Staff needs this information to determine whether the appropriate allocation of cost recovery is occurring between the DIR and other riders. This information will also help Staff ensure that the Company is adhering to the accrual schedules ordered in the previous rate case.

   2015 Audit Status per Company: The Company stated that it has worked with Staff and implemented Staff's recommendations, beginning with the filing for September 2015 plant balances.[51]

   Blue Ridge's Comment: The Company December 2016 Distribution Plant balance did not agree with the Ohio Power Distribution Plant amount reported on the FERC Form 1. The fourth quarter 2016 FERC Form 1 reports a Distribution Plant balance of $4,454,773,907[52] while the fourth quarter 2016 DIR filing reported $4,454,772,671 for a difference of $1,236. The Company's filing did not include an explanation of why the DIR filing was different from the FERC Form 1 filing. While the Company provided an explanation for the difference during discovery,[53] the Company is not in compliance with the Commission's Order to provide the reconciliation within the DIR filing. Blue Ridge recommends that the Company provide the reconciliation to the FERC Form 1 as ordered by the Commission.

4. Revenue Collected by Month in the DIR: AEP should also be directed to detail the DIR revenue collected by month and to date in its filings to demonstrate compliance with the annual revenue caps authorized by the Commission.

   Status per Company: The Company stated that it has worked with Staff and implemented

[50] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 30.
[51] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 31.
[52] FERC Form 1, 2016/Q4, page 207, line 75.
[53] AEP Ohio's response to 2016 Data Request 1-007. The Company explained that the DIR balances at December 31, 2016, do not equal the plant balances from the 2016 FERC Form 1 due to a misclassification between utility account 36200 (Distribution Plant) and utility account 35300 (Transmission Plant). This transaction should have been in Transmission account 35300, but was approved with the incorrect 36200 account. The DIR filing reflects the adjustment made in April 2017 to correct the error.

Staff's recommendations, beginning with the filing for September 2015 plant balances.[54]

Blue Ridge's Comment: The Company included a workpaper within the DIR filing comparing the monthly and to-date DIR revenue requirement with the billed DIR. The monthly DIR revenue requirement was generated by a run of the DIR calculation based on DIR plant every month. The Company assumed that the Billed DIR amount equals the revenue received. No further work is required.

5. Highlighting and Quantifying DIR Capitalization Policy: Any further changes AEP proposes to make to its capitalization policy should be highlighted and quantified in the DIR filing preceding the implementation of the change. This action would allow the Commission to consider the proposed change and ensure that there is no inappropriate recovery from AEP customers.

   2015 Audit Status per Company: The Company stated that it has worked with Staff and implemented Staff's recommendations, beginning with the filing for September 2015 plant balances.[55]

   Blue Ridge's Comment: The Company stated that no capitalization policy changes have been reported by the Company since the prior filing.[56] However, part of Blue Ridge's review process is to obtain any changes to the Company's policies and procedures from the prior audit. The Company's update included a change made to the capitalization policy by which a retirement unit for Energy Control Devices and Displays was established. This equipment works in conjunction with smart meters and can be used to provide the customer and AEP with real time information regarding energy costs and use. The equipment is new-use technology at AEP.[57] Although this equipment attaches to the meter, it is purchased separately and can be replaced separately, qualifying it as a stand-alone retirement unit. Blue Ridge recommends that the Company highlight and quantify this and any other changes to the capitalization policy in the DIR filing preceding the implementation of the change.

6. Filing of an Updated Depreciation Study by November 2016: AEP to file a fully updated depreciation study by November 2016 with a study plant date of December 31, 2015.

   Status per Company: A depreciation study was performed for Ohio Power on the plant-in-service balances as of December 31, 2015, and filed with the Public Utilities Commission of Ohio staff on November 21, 2016. The depreciation study was filed to comply with the order in Case No. 13-2385-EL-SS and Case No. 13-2386-EL-AAM where the Commission adopted the Staff's recommendation to require that Ohio Power file an updated depreciation study by November 2016. No depreciation rates were updated for Ohio Power as a result of the depreciation study that was filed with the Public Utilities Commission of Ohio Staff.[58]

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[54] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 31.
[55] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 31.
[56] AEP Ohio's response to 2016 Data Request 1-010.
[57] AEP Ohio's response to 2016 Data Request 1-011, including Attachment 1.
[58] AEP Ohio's response to 2016 Data Request 1-024.

Blue Ridge's Comment: The Company filed an updated depreciation study. No additional work is required.

OCC's Property Taxes Recommendation

The Commission adopted OCC's recommendation to modify the property tax calculation. The Commission ordered the DIR property tax be modified as follows: for the purpose of calculating property taxes, the depreciation reserve should be adjusted to eliminate the cumulative amortization of the excess depreciation reserve since December 31, 2011 (when rates in Case Nos 11-351-EL-AIR and 11-352-EL-AIR went into effect). This adjustment will reflect the change in the base on which property taxes are calculated more accurately and net plant to which the property tax is applied.[59] In the 2015 audit, the Company stated that it has implemented the Commission's order with respect to the property tax adjustment beginning with the DIR filing for June 2015 plant balances. The Company modified the depreciation reserve in the Company's DIR filings for June 2015 and subsequent plant balances as detailed in the testimony of OCC witness Effron. The adjustment is equal to $2,900,000 multiplied times the number of months subsequent to December 2011.[60]

Blue Ridge reviewed DIR calculation and found, for the purposes of calculating property taxes, the depreciation reserve has been offset as ordered by the theoretical reserve offset. The following table provides the offset amounts.

Table 3: Theoretical Reserve Offset

Period	Adjustment	# of Months	Calculated Theoretical Reserve	Amount Offset in DIR
4th Quarter 2015	$ 2,909,000	48	$139,632,000	$139,632,000
1st Quarter 2016	$ 2,909,000	51	$148,359,000	$139,632,000
2nd Quarter 2016	$ 2,909,000	54	$157,086,000	$122,178,000
3rd Quarter 2016	$ 2,909,000	57	$165,813,000	$130,905,000
4th Quarter 2016	$ 2,909,000	60	$174,540,000	$139,632,000

Blue Ridge found the application of the theoretical reserve offset prior to calculating property tax is not unreasonable.

MATHEMATICAL ACCURACY

Blue Ridge validated the mathematical calculations in the Company's revenue requirement model for each quarter and found them not unreasonable. The following sections address the verification and validation of the various components of the DIR, including net plant in service, exclusions, ADIT, carrying charge rate, revenue offset, annual cap and over or under recovery, and the annual base distribution revenue.

[59] Case No. 13-2385-EL-SSO, Opinion and Order dated February 25, 2015, page 46 and the Prefiled Testimony of David Effron (OCC Exhibit 18, pages 8-11.

[60] Case No. 16-01-EL-RDR, Blue Ridge's Report dated August 5, 2016, titled "Compliance Audit of 2015 Distribution Investment Rider (DIR) of Ohio Power Company d/b/a AEP Ohio," page 32.

NET PLANT IN SERVICE

The DIR allows carrying costs on net distribution plant[61] associated with FERC Plant Accounts 360-374 for plant placed in service after date certain, August 31, 2010.[62]

The accumulated reserve for depreciation is accumulated based on the Commission-approved depreciation rates by FERC account.[63] The last depreciation study was performed based on plant in service at December 31, 2009. New deprecation rates based on this study were approved in the distribution rate Case No. 11-351-EL-AIR et al. Settlement. The rates went into effect in January 2012.[64] The Company filed an updated depreciation study on November 2016. No depreciation rates were updated for Ohio Power as a result of the depreciation study that was filed with Staff.[65]

Blue Ridge confirmed that the Company used the date certain net plant approved by the Commission in Case No. 11-351-EL-AIR et al.[66] in the Rider DIR revenue requirement model.[67] The date-certain net-plant-in-service amounts by Company are shown in the following table.

Table 4: Net Distribution Plant by Company as of August 31, 2010

Description	Columbus Southern	Ohio Power	Total
Distribution Plant	$ 1,749,696,000	$ 1,596,229,000	$ 3,345,925,000
Accumulated Depreciation	$ 729,024,000	$ 524,149,000	$ 1,253,173,000
Net Distribution Plant	$ 1,020,672,000	$ 1,072,080,000	$ 2,092,752,000

The incremental net plant for which the Company is seeking recovery (prior to any exclusions discussed later in this report) is shown in the following table.

Table 5: Incremental Net Plant in Service Included in Rider DIR

Description	4th Q 2015	1st Q 2016	2nd Q 2016	3rd Q 2016	4th Q 2016
Distribution Plant as of 8/31/2010	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000
Accumulated Depreciation as of 8/31/2010	(1,253,173,000)	(1,253,173,000)	(1,253,173,000)	(1,253,173,000)	(1,253,173,000)
Net Distribution Plant	**$ 2,092,752,000**	**$ 2,092,752,000**	**$ 2,092,752,000**	**$ 2,092,752,000**	**$2,092,752,000**
Quarterly Distribution Plant	$ 4,284,075,232	$ 4,321,225,192	$ 4,359,406,297	$ 4,398,095,387	$ 4,454,772,671
Quarterly Accumlated Depreciation	(1,478,930,754)	(1,489,109,363)	$ (1,501,020,553)	$ (1,509,423,230)	$ (1,521,238,975)
Net Distribution Plant	**$ 2,805,144,478**	**$ 2,832,115,829**	**$ 2,858,385,744**	**$ 2,888,672,157**	**$2,933,533,696**
Change in Distribution Net Plant	**$ 712,392,478**	**$ 739,363,829**	**$ 765,633,744**	**$ 795,920,157**	**$ 840,781,696**

The $4,454,772,671 December 2016 Distribution Plant in the above table did not agree with the Ohio Power Distribution Plant amount in the FERC Form 1. The fourth quarter 2016 FERC Form 1 reports a Distribution Plant balance of $4,454,773,907[68] for a difference of $1,236. The Company explained that the difference was due to a misclassification between utility account 36200 (Distribution Station Equipment) and utility account 35300 (Transmission Station Equipment).

61 Net Distribution Plant is Gross Plant less the Accumulated Reserve for Depreciation.
62 August 31, 2010 was the date certain in the Company's most recent distribution base case (Case No. 11-351-EL-AIR).
63 Case No. 13-419-EL-RDR, AEP Ohio response to 2013 Data Request 2-004.
64 Case No. 13-419-EL-RDR, AEP Ohio response to 2013 Data Request 1-015, 2-005, 2016 Data Request 1-024, and Case No. 11-351-EL-AIR, Order dated 12/14/11 approving the Settlement dated 11/21/11, Attachment D.
65 AEP Ohio's response to 2016 Data Request 1-024.
66 Case No. 11-351-EL-AIR, et al., Order dated December 14, 2011, Settlement Attachment A, pages 2 and 5.
67 WP V&V DIR Model BR-DR-1-002 Attachment 4.
68 FERC Form 1, 2016/Q4, page 207, line 75.

The transaction should have been in transmission account 35300, but was approved with the incorrect distribution 36200 account. The DIR filing reflects the adjustment made in April 2017 to correct the error.[69]

FERC Form Validation

The DIR is updated quarterly based on the incremental increase in the net plant balance as shown on the FERC Form 1. Blue Ridge compared the gross plant and accumulated depreciation amounts in the DIR filing to the 2016 FERC Forms 1 for Distribution Plant. As noted above, the only exception was the $1,236 difference in the fourth quarter 2016. The Company's explanation of the difference was not unreasonable.

Work Order Detailed Transactional Testing

The Company provided a list of 21,413 work orders that support gross plant in service included in the DIR from January 1, 2016, through December 31, 2016.

(1) Determining Work Order Sample

From this list, Blue Ridge selected 47 work orders for transactional testing using the probability-proportional-to-size (PPS) sampling technique,[70] a statistically valid sampling technique that would allow conclusions to be drawn in regard to the total population. Additional work orders were selected based on professional judgment with a focus on the selection of individual (rather than blanket) work orders that have a high-dollar value and, if possible, could also be inspected in the field to determine its used-and-useful status (in accordance with work order testing step T10 discussed later in this document).

(2) Conducting Work Order Testing

The Company provided descriptions of the projects included in the work order sample. In general, the projects may be categorized based on the following types of additions, replacements, adjustments, and transfers.

1. Installation of underground and overhead conduit, conductors, and devices
2. Meters
3. Station equipment
4. Street lighting
5. Poles, Towers and Fixtures, Land Acquisition or transfers, Services
6. Line Transformers
7. Reclassification of Completed Construction not classified to Utility Plant in-service
8. Installation on customer premises
9. Structures and Improvements

The following areas were the determined focus for transactional testing review:

- Project descriptions to determine exclusions from the DIR
- Project justifications
- Project actual versus budgeted cost
- Variance explanations
- Reasonableness of the actual in-service dates in comparison to the estimated in-service dates

[69] AEP Ohio's response to 2016 Data Request 1-007.
[70] WP BRCS AEP 2016 DIR Audit Work Order Testing Matrix.

- Proper charge of the actual detailed cost to the proper FERC account
- AFUDC charge on the work order (and if so, was it appropriate)
- Timeliness of recording of asset retirements for replacement work orders
- Appropriate charge of cost of removal and salvage, if applicable

To satisfy these areas of focused review, Blue Ridge formulated the objective criteria into ten transactional testing steps, labeled T1 through T10.[71] Blue Ridge's observations and findings against the criteria follow:

T1: The work is appropriately includable in the DIR; the DIR includes plant in service associated with distribution net investment associated with FERC Plant Accounts 360–373
- T1a: Exclusion of Plant Held for Future Use
- T1b: Exclusion of gridSMART II Net Plant Adjustment (recovered through GS Rider); review project descriptions to determine that those descriptions exclude any discussion of AMI, Smart Grid, and Smart Current
- T1c: Exclusion of Incremental Vegetation Management Net Plant

T2: Work order package contains the project approval documentation, or work order was approved at the project level

T3: For specific work orders (i.e., not blankets or multi-year projects, such as pole and meter replacements), the work order package contains project justification

T4: Project costs are within the approved budget, and explanations and approval for cost overruns +/- 15% of budget were provided

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

T6: Project detail indicates assets were retired and costs are incurred for cost of removal and salvage; if applicable, complete T6a and T6b
- T6a: Replacement work orders: the date assets were retired, cost of removal date, and date of replacement asset in service are in line
- T6b: Replacement work orders: cost of removal has been appropriately charged

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

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

T9: The work order in service and closed to EPIS within a reasonable time frame from project completion; if not, AFUDC was stopped

T10: For work performed in 2016, this project is a candidate for field verification to determine if it is used and useful

The results of the detailed transaction testing performed on the work order sample are included in the workpapers.[72] Specific observations and findings about the testing are listed below.

T1: The work is appropriately includable in Rider DIR. Rider DIR includes plant in service associated with distribution net investment associated with FERC Plant Accounts 360–373

Blue Ridge found that the work tested was properly includable in the DIR. All work represents Distribution in FERC accounts 360–373 (Distribution plant and Street Lights).

[71] WP BRCS AEP 2016 DIR Audit Work Order Testing Matrix.
[72] WP BRCS AEP 2016 DIR Audit Work Order Testing Matrix.

T1a: Exclusion of Plant Held for Future Use

Blue Ridge found that the work order sample did not contain any work orders or costs associated with Plant Held for Future Use and that all work contained in the work order sample appeared to be used and useful.

T1b: Exclusion of gridSMART II Net Plant Adjustment (recovered through GS Rider). Review project descriptions to determine that those descriptions exclude any discussion of AMI, Smart Grid, and Smart Current

Blue Ridge found that the sample did not include any identified gridSMART work orders.[73] In addition, Blue Ridge reviewed the project description for each FERC account 370 (meters) work order to confirm that all gridSMART phase II work orders were excluded from the DIR. While verifying, Blue Ridge found two work orders within the population that were for the purchase of AMI replacement meters and AMR meters (i.e., work order W0023969-AMI Meter Blanket Purchase Non Project AMI Meters Install and Retirement/Removal non-project AMI meters for $1,291,693 and work order 7900299-Purchase Meters & Capitalize Initial Cost for $6,083,661). These work orders are blankets for the replacement of AMI meters that were installed under gridSMART Phase 1. Because the gridSMART Phase 1 project has been completed and the costs will be transferred to the DIR, these costs are appropriately included within the DIR. [74]

T1c: Exclusion of Incremental Vegetation Management Net Plant

The Company provided a list of vegetation management work orders that had been excluded from the DIR. Blue Ridge reviewed the project description for each FERC account 365 work order to confirm that all Incremental Vegetation Management work orders had been excluded. In testing, Blue Ridge identified two work orders that required further review:

1. W0025973-OPCo D Forestry - 2015 Program for $7,917,946, which is the reversal of the 2015 Forestry program from Completed Construction not classified to Utility Plant in Service
2. W0027041-Forestry - Distribution Capital Widening for $140,213

Both work orders are recovered in the Enhanced Service Recovery Reliability Rider (ESRR) and are being correctly excluded from the DIR. The ESRR accumulates the total costs in the above work orders, but for each month's activity, a baseline applicable to that month will be removed and only the incremental change in investment is included in the ESRR. Those monthly baseline amounts are based on the monthly values from 2009.[75]

T2: Work order package contains the project approval documentation, or work order was approved at the project level

Blue Ridge reviewed the work orders in the sample to determine whether the work order package contained the appropriate project approval(s). The Company does not approve individual work orders.[76] Most distribution work funding is approved at a project or higher level. The Company's distribution work is performed through blanket or annual budgeted project/work

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[73] AEP Ohio's response to 2016 Data Request 1-038 Attachment 1.
[74] WP BRCS AEP 2016 DIR Audit Work Order Testing Matrix and AEP Ohio's response to 2016 Data Request 1-034.
[75] AEP Ohio's response to 2016 Data Request 6-005.
[76] AEP Ohio's response to 2012 Data Request 4-001b.

orders. These work orders are part of a group of work the Company executes on an annual basis or routinely over multiple years. project/program is normally performed using a series of work orders. Costs are managed to an overall budget.[77] While one funding project is approved each year, the scope of work may cover more than one budget year.[78] The work is generally performed on a series of work orders and work releases. Monitoring is done on each work order, but the costs are managed to the overall project/program budget.[79]

Blue Ridge reviewed the project/program approval documentation and found that the Company adhered to its stated approval policy and found that all work orders sampled contained the appropriate approvals.[80] Further discussion about the policies and procedures for approving capital activities is contained in the Policies and Procedures section of this report.

T3: For specific work orders (i.e., not blankets or multi-year projects, such as pole and meter replacements), the work order package contains project justification

Blue Ridge reviewed work orders in the sample to determine whether the work order packages contained the appropriate project justifications. Blue Ridge found all sample project work orders included justifications that were not unreasonable.[81] However, as indicated below, some of the work orders did not have alternatives considered or, although having considered alternatives, did not document those alternatives. Specific work orders, unless mandated, generally have a defined scope, estimated start/stop dates, and detailed explanations to support the project.[82]

Capital Spares Work Orders

Blue Ridge noted three work orders, totaling $1,860,202, within the sample that were for the purchase of capital spares.

- Work order 42473073 purchase of a Spare 50 MVA Transformer for $735,842
- Work order 42431638 purchase of a Spare 25 MVA Transformer for $554,238
- Work order 42412188 purchase of a Spare 20 MVA Transformer for $570,122

The Company explained the reason the equipment was purchased and supplied the policy that supports the inclusion of those spares in utility plant.[83] The Company believes that the inclusion of capital spares in the DIR is appropriate for two reasons:

1. The language of Commission Order 11-046-EL-SSO, dated August 8, 2012, allows the Company to include the recovery of capital cost for distribution infrastructure investment to improve reliability for customers.
2. The calculation of the DIR as approved by the Commission supports recovery of capital spares and allows the Company to recover the entirety of the distribution plant accounts as defined in the FERC USofA except for specific exclusions.[84]

The Company does concede that an option is to borrow a spare from another utility. However, those spares would need to be compatible to the Company's system in terms of voltage, capacity,

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[77] AEP Ohio's CONFIDENTIAL response to 2012 Data Request 4-001, attachment 8.
[78] AEP Ohio's CONFIDENTIAL response to 2012 Data Request 4-001, attachment 9.
[79] AEP Ohio's CONFIDENTIAL response to 2012 Data Request 4-001 and attachments 8 and 9.
[80] WP BRCS AEP 2016 DIR Audit Work Order Testing Matrix.
[81] AEP Ohio's response to 2016 Data Request 3-001, Attachments 2 through 7 and Attachment 7 Supplement.
[82] AEP Ohio's response to 2016 Data Response 3-001, including Attachments.
[83] AEP Ohio's response to 2016 Data Request 6-009 and Attachment 1.
[84] AEP Ohio's response to 2016 Data Request 11-001.

and standards. Borrowing would provide a temporary solution, but the Company would also need to purchase a replacement which they estimate would take 9 to 11 months, depending on the manufacturer.[85]

Blue Ridge understands according to Company policy and FERC accounting, the Company is allowed to record capital spares in utility plant when the justifications meet a stated set of criteria. The spares in this case did meet the stated set of criteria. Blue Ridge expressed concern whether an asset that was not used and useful should be recovered through the DIR. The Company defended its position that the capital spares are appropriately included in the DIR:

> b) The Company believes that recovery of the capital spares has been accepted by the Commission for two reasons: One is the language of the order, and the other is how the DIR revenue requirement is developed.
>
> As noted on page 46 of the Commission's order issued August 8, 2012, in case number 11-046-EL-SSO, et al, (August 8th, 2012) *As authorized by Section 4928.143(B)(2)(h), Revised Code, an ESP may include the recovery of capital cost for distribution infrastructure investment to improve reliability for customers.*.
>
> In a subsequent paragraph on page 46 of the order it states: *The Commission finds that, adoption of the DIR and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and better align the Company's and its customers' expectations. The Company appears to be p lacing sufficient proactive emphasis on and will dedicate sufficient resources to the reliability of its distribution system. Having made such a finding, the Commission approves the DIR as an appropriate incentive to accelerate recovery of AEP Ohio's prudently incurred distribution investment costs.*
>
> Finally on page 47 of the order, the Commission opines that *'We believe that it is* ***detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure*** *[emphasis added] and, therefore find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs*.
>
> The Commission's language from page 47 supports a proactive approach to the management of its distribution infrastructure. Capital spares allow the Company to do this efficiently. It allows the timely replacement of critical, high dollar assets with long order lead times, thus ensuring customers enjoy reliable service with minimum impact in the event of the failure of one of this assets.
>
> The calculation of the DIR as approved by the Commission supports recovery of capital spares. The Commission allows the Company to

[85] AEP Ohio's response to 2016 Data Request 8-004.

> recover the entirety of the distribution plant accounts as defined in the FERC's Uniform Standard of Accounts ("USA"), with the exception of specifically defined amounts related to gridSmart II and the Enhanced Service Security Rider (Vegetation Management), which have their own recovery mechanisms. The FERC USA specifies which accounts an asset has to be recorded in, and does not differential between capital spares.
>
> In addition, the DIR "also provides the Company with a timely cost recovery mechanism for its prudently incurred distribution infrastructure investment costs and is expected to reduce the frequency of base distribution rate cases." (Commission O&O Case No. 12-3129). The Company's policy and procedures around capital spares does in fact merit a reliability component of the distribution system, but it also supports the prudency of the Company's decisions in order to provide safe and reliable service.[86]

While the Company defended its position that the capital spares are appropriately included in the DIR, Blue Ridge recommends further discussion on this issue. Blue Ridge recommends the Company look into borrowing capital spares, if it makes economic sense, or, at a minimum, perform an analysis to compare renting versus the purchase of a capital asset.

<u>Other Work Orders with and without Alternatives</u>

- Work Order 42244260 - Construct 9.275 MVA Dist. Station: Cost $2,838,671. Killbuck substation

The Company's justification for the project concluded that rebuilding the Killbuck substation was the most cost-effective alternative.[87] However, the Company did not provide adequate alternative solutions in the project justification. The Company indicated that it did not consider an alternative location because the undeveloped property at the existing location was sufficient in area to rebuild the station.[88] The Company performed a specific analysis to determine the savings in O&M related to retiring the old station.[89]

Blue Ridge does agree with the alternative selected by the Company. However, we recommend that in order to complete the justification process, the Company provide reason(s) one alternative is better than another and, if savings are estimated, indicate how those savings are to be realized.

- Work Order 42393169 - Barnesville - replace control building: Cost $895,677

Blue Ridge asked for a cost benefit analysis and estimated payback period for this project. The Company objected to the requests and indicated that the payback period and cost-benefit analysis are not relevant for most distribution investments where the Company has an obligation to provide safe and reliable service. Despite the objection, the Company did state that it did not perform a cost benefit analysis or determine a payback period but did consider a repair alternative. The Company also stated that projects like the one in question are the backbone of the system and the decision to replace the building was for public safety.[90] Blue Ridge agrees that the project appears necessary,

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[86] AEP Ohio's response to 2016 Data Request 11-001.
[87] AEP Ohio's response to 2016 Data Request 3-001, Attachment 6.
[88] AEP Ohio's response to 2016 Data Request 8-001.
[89] AEP Ohio's response to 2016 Data Request 8-001.
[90] AEP Ohio's response to 2016 Data Request 8-003.

but for any project, implemented for reliability or otherwise, Blue Ridge recommends that the Company document operational and/or economic alternatives and, if no alternatives were considered, document the reason(s).

- Work Order 42263333 - DENNISON - replace 10.5 MVA XFMR: Cost $3,645,031

In reviewing the project justification of this work order, economic alternatives were not documented. The Company, however, did document operational reasons for selecting this alternative.[91] Blue Ridge considers the operational considerations not unreasonable.[92]

- Work Order 42487877 - SPARTA SWITCH: SPARTA PUMPING METERING: Cost $459,359

The Company did not document that it considered alternatives or performed a cost benefit analysis regarding this work order. However, the reasons for selecting this project included reliability, security, and bandwidth.[93] The operational reasons for selecting this alternative are not unreasonable.

- Work Order 42440744 - 106 Reversal; D/OP/IDAHO-REPLFAILED69KVTRF; Station Equipment: Cost $594,771

This work order reversed Completed Construction Not Classified and charged the work order to Utility Plant in Service. The reversal does not impact net plant. The project was intended to improve reliability. While the economic analysis did not indicate how reliability improved, the Company did, upon further request, explain that the system did benefit from the work. It also noted this project is one of 126 active projects that, for both Transmission and Distribution, benefit the customer through improved reliability. The explanations provided by the Company are not unreasonable.[94]

T4: Project costs are within the approved budget, and explanations and approval for cost overruns +/- 15% of budget were provided

Blue Ridge's review included an analysis of whether work orders in the sample were within +/-15% of their approved budget. Of the 47 work orders in the sample, 38 were either under budget or within the +/= 15% tolerance level.[95]

The following four work orders within the program DISTBLKOP were over budget by 18% in the customer-service segment and 29% in the transformer-blanket segment.[96]

- Work order DOP0233014 – Customer Service, CI – new service
- Work order DOP0244155 – Equipment removal Columbus Center
- Work order BOP0000001 – conductor all sizes and types

The Company indicated that projects included in the customer-service blanket are subject to the construction schedule of the parties requesting work.[97] The transformer blanket is subject to customer activity and the need to maintain an adequate inventory.[98] The 2016 budget is established in the summer of 2015. The budget is part of a large, overall budget developed for all AEP, including

[91] AEP Ohio's response to 2016 Data Request 8-002.
[92] AEP Ohio's response to 2016 Data Request 8-002.
[93] AEP Ohio's response to 2016 Data Request 6-010.
[94] AEP Ohio's response to 2016 Data Request 6-010.
[95] WP AEP 2016 DIR Audit Work Order Testing Matrix T4.
[96] AEP Ohio's response to 2016 Data Request 3-001 Attachment 2.
[97] AEP Ohio's response to 2016 Data Request 6-011.
[98] AEP Ohio's response to 2016 Data Requests 6-007 and 6-011.

Ohio. AEP has indicated that they manage to the overall budget based on individual work components of the work plan.[99]

Blue Ridge believes that the explanations are not unreasonable. However, because the budget is established six months in advance of the budget year, inaccuracy of estimates is a distinct possibility. The inaccuracy potential in establishing the budget six months in advance could result in the actual being over or under the estimate depending on the overall level of actual customer activity for a given year. Some of that activity is customer dependent and, therefore, outside the direct control of the Company. Blue Ridge recommends that the Company continue to manage to the budget and document reasons for overage or underage of actual charges both when those reasons are outside the direct control of the Company and when those reasons are within the direct control of the Company. Therefore, as long as the Company manages the budget and can adequately explain the overage or underage, the variance from budget can be shown as not resulting from lack of management control.

The following two work orders within the program DISTGMGH were over budget by 33% in the pole-replacement program and 89% in the sectionalizing program.[100]

- Work order DOP0250402 – Conductor all sizes and types
- Work order DOP0247782 – Priority Z

The Company indicated that additional pole replacements were performed in 2016 beyond those contemplated when the 2016 work plan was developed, resulting in the sectionalizing program being over budget primarily due to that additional, non-contemplated work.. That work was made up primarily of additional reclosers.[101] The Company was attempting to catch up on the backlog of pole replacements. The budgeting process for poles is the same as it is for customer-service and distribution-transformer work discussed above.[102] The pole-replacement activity is more directly controlled by the Company than the customer-service work, yet the explanations the Company gave were not unreasonable. Pole replacement is an important activity to ensure safe and reliable service.

The following three work orders were over budget by more than 15%, but the Company's explanations were not unreasonable.[103]

- Work order DOP0256277 – Install misc. duct – over budget by 22.3% (Estimate = $1,330,754 vs. Actual = $1,627,599)
- Work order T0154738 – Voltage regulator – over budget by 60.3 % (Estimate = $11,654,701 vs. Actual = $18,680,659)
- Work order 42244260 - KILLBUCK - CONSTRUCT 9.375 MVA DIST STATION required a change order that increased the original estimate by 24%.[104]

The Company explained that the project involving work order 42244260 is primarily a Transmission-capital blanket with only a portion in Distribution. The Company stated the original work plan was incomplete, requiring adjustment. Converting a complete circuit in one step is difficult to organize. The contractor work orders did not address all work required, and several clearance violations were not addressed by the contractor. Several change orders had to be written

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[99] AEP Ohio's response to 2016 Data Requests 11-002 and 11-003.
[100] AEP Ohio's response to 2016 Data Request 3-001 Attachment 2.
[101] AEP Ohio's response to 2016 Data Request 6-012.
[102] AEP Ohio's response to 2016 Data Request 11-004.
[103] AEP Ohio's response to 2016 Data Request 6-012.
[104] AEP Ohio's response to 2016 Data Request 6-010.

that were not part of the original scope. In addition, a contractor was ordered off the job for safety violations. The sum of all adjustments resulted in an increase in cost from the original budget.[105] Blue Ridge understands that as work progresses, events can occur requiring change to scope and/or cost. However, the work plan and management of a project is within the direct control of the Company. Therefore, Blue Ridge recommends that when large projects are developed, the Company place more emphasis on ensuring the work plan is complete and that the contractors performing the work understand the requirements from both work and safety perspectives.

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

Blue Ridge determined that, except as noted below, the costs recorded in PowerPlant support the work order charge, and the categories of cost are not unreasonable.

Several work orders in the sample contained the following cost elements, totaling approximately $136,511:[106]

1. Cost Element 141: Incentive Accrual Dept. Level—used to record Distribution, Customer Operations and Regulatory Services Incentive Plan expense
2. Cost Element 143: Other Lump Sum Payments
3. Cost Element 145: Stock-based compensation—used to record Performance Share Incentive expense
4. Cost Element 154: Restricted Stock Incentives—used to record Restricted Stock Unit expense
5. Cost Element 155: Transmission Incentives—used to record Transmission Incentive Plant expense

The Company explained that the charges are components of the Company's overall compensation that in part make up the reasonable and market-competitive total compensation package provided to employees. Those cost components allow the Company to attract, retain, motivate and engage suitably skilled, experienced, and knowledgeable employees. According to the Company in the AEP Ohio distribution cases 11-0351-EL-AIR and 11-0352-EL-AIR, the Commission accepted the inclusion of incentives in the development of the revenue requirement.[107]

Blue Ridge does not consider these costs as either payroll, payroll related, or appropriate overhead costs that benefit the project(s) and, therefore, recommends that these costs be removed from the DIR. Blue Ridge also recommends that the Company review the cost detail for the total population of work orders included in the DIR and remove the costs associated with these five identified cost elements from the DIR since the Company failed to demonstrate how these costs directly benefit the DIR or have not been considered elsewhere in an overhead allocation

T6: Project detail indicates that assets were retired and costs are incurred for cost of removal and salvage; if applicable, complete T6a and T6b

For replacement work orders, Blue Ridge found assets were retired and cost of removal was charged. In some cases, the Company recorded salvage for the sale or scrap value of assets. When

[105] AEP Ohio's response to 2016 Data Request 6-010.
[106] WP BR-INT-2-001 Attachment 8 (to Remove Certain Cost Elements from DIR).
[107] AEP Ohio's response to 2016 Data Request 11-006.

equipment is sold for other than scrap, the proceeds are charged to the accumulated reserve for depreciation.[108]

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 date of replacement asset in service are in line

All assets that were retired were removed from plant. The date assets were retired and the costs of removal charged were not unreasonable.

T6b: Replacement work orders: cost of removal has been appropriately charged

Blue Ridge found that there were no work orders in the sample with inappropriately charged cost of removal.[109]

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

Blue Ridge found that all work orders were closed to the proper FERC accounts based on the description of the work being performed.[110]

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

The Company does not track in-service dates.[111] An inactive work order report is used to track work orders that have not had any activity (charges) for six months.[112] The policy associated with the report is not unreasonable.

Blue Ridge also found that work orders on the fourth quarter 2016 inactive work order report totaled $8.896 million, net of credits, and were inactive from between 13 to 138 months. Most of the work orders on the inactive work order report had status comments that read “received.” Reasons for remaining open included the following explanations: “in process of being closed,” “make ready” (either waiting for a customer to pay or other undetermined reason), and “to be worked when crews are available.” Fifty-nine of the work orders, totaling approximately $139,700, have been cancelled and will be charged to expense; therefore, will not affect the DIR. Approximately 114 work orders, totaling $2.747 million, are completed and/or in-service. The $8.896 million total of inactive work orders in the fourth quarter of 2016 is 71% higher than the prior year (2015), even though most of the work orders are small. Both the range of months those work orders have been inactive and the increase from the previous year appear excessive.

Blue Ridge recommends the Company continue to monitor inactive work orders that appear on the report, striving to resolve outstanding issues within a reasonable time frame of six months to reduce the total dollar value of inactive work orders. This recommendation appeared in last year’s report as well, and we agreed with the Company’s response that work orders may remain inactive for several reasons, including reasons that are outside the Company’s control (e.g. a work order waiting for a customer’s action). We also acknowledge the Company’s statement that monitoring is

108 AEP Ohio’s responses to 2016 Data Request 7-022 and 2012 Data Request 1-006.
109 WP AEP 2016 DIR Audit Work Order Testing Matrix T6b.
110 WP AEP 2016 DIR Audit Work Order Testing Matrix T7.
111 AEP Ohio’s response to 2016 Data Requests 1-044, Attachment 2, and 1-047.
112 AEP Ohio’s response to 2016 Data Request 1-044, Attachment 2.

conducted on the inactive work order report. However, because of the significant duration of some of the inactive work orders, by this recommendation, Blue Ridge is continuing to stress the importance of focus to ensure that outstanding issues able to be resolved are resolved.

T9: The work order in service and closed to EPIS within a reasonable time frame from project completion; if not, AFUDC was stopped

Blue Ridge found that all project work orders in the sample were closed to plant in service within a reasonable time frame from project completion.

T10: For work performed in 2015, this project is a candidate for field verification to determine if it is used and useful

Blue Ridge identified six work orders within the sample as candidates for field visits.

Field Inspections

Blue Ridge selected six projects for field verification from the work order sample. The purpose of the field verification was to determine whether the assets had 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 specified assets that can be physically seen and were installed within the scope period of this review. The judgment sample was based on large-dollar work orders. Work orders/projects were excluded from selection for the following reasons:

1. The work order assets could not be visually seen because they were underground or otherwise out of sight.
2. The work was a blanket/project including multiple assets installed at various locations, making it impractical to locate. In most instances, the dollar value of such work orders is small. Examples of work orders in this category include the installation/replacement of meters, poles, or distribution transformers, all of which are installed at multiple locations.
3. The dollars were a transfer or reclassification (reversal) of completed construction not classified (FERC 106).

Experienced staff from the Public Utilities Commission of Ohio, with assistance from AEP Ohio representatives, conducted the field verifications on June 13, 15, 16, and 19 of 2017. Staff was provided 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 list includes the objectives of the field inspection:

- The assets were operational (used and useful) and providing service to the customer.
- The purpose of the project was reasonable.
- The assets that were installed were in accordance with the original scope of work and no assets were installed that were not in the original scope of work.
- The equipment that was installed matched the equipment that was capitalized to the DIR.
- Company personnel understood the scope of work and were able to provide staff with detailed answers to questions about the work.
- Problems identified during the process of construction were identified and discussed.
- The Company provided reasons (either to Staff or Blue Ridge) for any variances from budget that were greater than 20%.
- Staff was able to take pictures in support of the field observations.

The following projects were field inspected:

1. Work order 42244260—Construct 9.275MVA Dist. Station 42244260 – KILLBUCK Project DR14A0001. Rebuild existing KILLBUCK station. Rebuilding the station will enhance area reliability. The project also includes retiring a 34.5k kv extension, switch and line extension; project also includes transfer of a 12kv feeder. This project is a multi-year project. The final cost of the project was $6,860,944. The in-service date was December 31, 2016.
2. Work order 42393169—Project TA2013003. Barnesville – replace control building. This project is part of a multi-year program to improve system reliability and dependability by replacing failed assets and assets in danger of imminent failure. This project covers both station equipment and transmission line components. The final cost of the project was $41,605,580[113] and was under the total authorized amount. The in-service date was December 31, 2016.
3. Work order T0162301—Project TA2015703 – HIGHLAND (CS). Replace failed 13kv CBs 26 and 27 Cap Proj. This project is part of an on-going, multi-year effort to improve system reliability and dependability. The project scope includes replacing failed assets and assets in danger of imminent danger. Final cost of the project was $43,530,573. The in-service date was August 2016, and the total project was scheduled to be completed December 31, 2019.
4. Work order 42473073—Spare 50MVA 148/34.5/13.8 Kv Auto Bixsy. This project is part of a three-year program to purchase/rebuild major spare Transmission equipment. This particular piece of equipment is Distribution. A three-year program allows the Company to secure equipment contracts to leverage purchase and obtain the best prices. Total program cost is $145,043,758. This purchase is $735,842, and the equipment was in service December 2016. The spare transformer was not operational and, therefore, not used and useful. Capital spares are considered utility plant in service based on FERC accounting guidelines. However, the issue is that they do not meet the standard for used and useful. Further discussion about capital spares and this issue is contained under testing step T3 above.
5. Work order 42263333—DENNISON replace 10.5 MVA XFMR with 20 MVA. Final cost was $4,390,956. The project was in service December 2016. The Company had projected that, in the summer of 2016, this transformer would be at 101% of capacity. Replacing the transformer alleviates the problem. This project also allowed the Company to establish a new distribution tie.
6. Work order 42453369—Project TP2014159 – BANE Stn. Install a 69-12kv DIST XFMR to service Augusta. Total final cost is $5,481,5635. Project was in service June 2017. This project is necessary because of increased load The existing system could not support the increased load without experiencing low voltage violations and possible load shed. This project is phase one of a two-phase project.

The six projects selected for field verification confirmed that the assets were installed and, except for the capital spare in work order 42473073, used and useful.[114]

Standard Cost Methodology

Standard Costs rates are used for the capitalization of meter and line transformer installation and removal costs.[115] Blue Ridge reviewed the Company's process of determining standard costs rates. The Company's standard cost formula is as follows:

[113] AEP Ohio's response to 2016 Data Request 6-001, Attachment 6.
[114] See Field Observation Folder.

Cost to Remove Meter = Bare Labor Cost + Fringe Cost + Transportation Cost

Where,

Bare Labor Cost = Standard Labor Time x Indirect Labor Adder x Standard Bare Labor Rate

Fringe Cost = Bare Labor Cost x Standard Fringe Factor

Transportation Cost = Bare Labor Cost x Standard Transportation Factor[116]

The Company stated that the standard cost process is changed as the need arises. The most recent change was in May 2016, when the Company changed from using an Indirect Labor Multiplier, which is based on a construction crew size of three people plus a qualified observer, to a Meter Labor Multiplier, which is based on a meter crew size of one person. The inputs to develop the Standard Costs are updated annually in May.[117]

The Bare Labor Rate used for the Standard Costs is obtained from Human Resources. The hourly rate for 2016 used for Bare Labor costs is derived by taking the average hourly rate for 2015 for the job titles associated with performing such work and grossing them up by 2.5 percent to develop an average for 2016.[118] Blue Ridge compared the 2016 Bare Labor costs to the Union Contracts and found it not unreasonable.[119]

Blue Ridge also reviewed the other components used in the standard cost formula (Indirect Labor Adder, Standard Fringe Factor, and Standard Transportation Factor) and found the methodology not unreasonable. However, during the review of the Standard Fringe Factor, the Company found that it had included the non-productive time rate twice. The impact was an overstatement of the fringe benefit loading rate by approximately 15 percent. As this rate is used for the capitalization of meter and line transformer installations and removal costs, its overstatement results in an overstatement in these capital amounts. The Company is developing an analysis of the impact and will provide it later.[120] Blue Ridge recommends that the Company correct the overstated Standard Fringe Factor, calculate the impact over the overstatement, and adjust the DIR.

Backlog

Blue Ridge reviewed the Company's backlog for unitization and found that AEP does not have a separate process that tracks a unitization backlog. However, the Company explained that the PowerPlant application is used to track capital work order activity at AEP. With a few exceptions, capital work orders are set up with a Standard Close Auto closing option. The system configuration for capital work orders with a Standard-Close-Auto closing option closes the work order charges to 1010001-Electric Plant in Service or 1080001-Accumulated Provision for Depreciation during the first closing after the expiration of a 90-day late-charge wait period. The completion date is entered into the work order when the majority of the charges are or will be on the work order within the next 90 days. The system begins timing the 90-day late-charge wait period from the completion date entered into the work order system. In the first closing after the expiration of the 90-day late-charge wait period, PowerPlant closes the charges on the work order to 1010001-Electric Plant in

115 AEP Ohio's response to 2016 data request BR-12-001.
116 AEP Ohio's response to 2016 data request BR-2-001.
117 AEP Ohio's response to 2016 data request BR-2-002.
118 AEP Ohio's response to 2016 data request BR-2-005.
119 WP Standard Cost to Labor Contract Comparison BR_DR_2-006_COMPETITIVELY_SENSITIVE_CONFIDENTIAL_Attachment_2.
120 AEP Ohio's response to 2016 data request BR-12-001.

Service for construction and to 1080001-Accumulated Provision for Depreciation of Plant for cost of removal and salvage dollars.[121] Blue Ridge found that the Company's process is not unreasonable, but we were unable to assess whether the Company has excessive backlog in unitization.

Insurance Recoveries

Blue Ridge reviewed the Company's insurance recoveries and found most recoveries are from vehicular or contractor equipment damage as shown in the following table.[122]

Table 6: Insurance Recoveries January 1, 2016—December 31, 2016

Cause	Number	Total Dollars
Contractor/ Contr. Equip.	131	(117,138)
Copper theft/vandalism	3	(2,871)
Damage to AEP property-marked correctly	17	(23,195)
Dig In Marked Incorrectly	8	(62,292)
Dig In No Locate Obtained	19	(10,265)
Dig-in (Not Marked)	15	(11,248)
Dig-In Unknown	27	(12,343)
Other	7	(736)
Other Utility	2	(2,969)
Public, misc	24	(5,799)
Trees-line	41	(16,788)
Vandalism	2	(1,302)
Vehicle	1,317	(2,001,850)
Grand Total	**1,613**	**(2,268,796)**

Although there were a large number of claims, the individual dollar amounts in most instances were small. Two claims paid were in excess of $50,000. An underground line was damaged due to a "Dig In Marked Incorrectly" ($55,606) and a transformer was damaged by a contractor's equipment ($52,061).[123] In addition to the paid claims, the Company has 323 pending claims totaling $125,213. Of the pending claims, 261 ($107,239) are for vehicular damage and 20 ($6,957) are from contractor's equipment.[124] The Company management procedures for claims[125] are not unreasonable, and recovered money is appropriately applied to the work order that repairs the damage. There was no indication that the insurance recoveries were not applied appropriately causing the DIR to be misstated.

Conclusion

In summary, Blue Ridge found several instances in its work order detailed transaction testing that indicate there may be costs included within the DIR that should be excluded. These indications included cost elements that are not an appropriate overhead charge for distribution plant and an overstated Standard Fringe Factor. (Further discussion is located under work order testing step T5 and in the section labeled Standard Cost Methodology.)

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[121] AEP Ohio's response to 2016 data request BR-1-047.
[122] AEP Ohio's response to 2016 data request BR 1-048, including Attachment 1, and WP Insurance BR-DR-1-048_Attachment _1.
[123] AEP Ohio's response to 2016 Data Request 1-048, including Attachment 1.
[124] WP Insurance Pending BR-DR-1-049_Attachment_1.
[125] AEP Ohio's response to 2015 Data Request 1-050.

EXCLUSIONS FROM DIR

The Commission ordered that capital additions recovered through other Commission-authorized riders be identified and excluded from the DIR Rider. The Company's tariff includes other riders as shown in the following list.[126]

1) Interruptible Power Rider
2) Universal Service Fund Rider
3) Bad Debt Rider
4) KWH Tax Rider
5) Residential Distribution Credit Rider
6) Pilot Throughput Balancing Adjustment Rider
7) Deferred Asset Phase-In Rider
8) Generation Energy Rider
9) Generation Capacity Rider
10) Auction Cost Reconciliation Rider
11) Electronic Transfer Rider
12) Power Purchase Agreement Rider
13) Basic Transmission Cost Rider
14) Transmission Under-Recovery Rider
15) Pilot Demand Response Rider
16) Energy Efficiency and Peak Demand Reduction Cost Recovery Rider
17) Economic Development Cost Recovery Rider
18) Enhanced Service Reliability Rider
19) gridSMART® Phase 1 Rider
20) gridSMART® Phase 2 Rider
21) Retail Stability Rider
22) Renewable Energy Technology Program Rider
23) Distribution Investment Rider
24) Storm Damage Recovery Rider
25) Alternative Energy Rider
26) Phase-In Recovery Rider

Blue Ridge reviewed each rider and determined that the gridSMART and Enhanced Service Reliability Riders are the only riders that include distribution plant that should be removed from the DIR to avoid double counting. Both of the riders germane to the exclusion criterion are discussed below.

Enhanced Service Reliability Rider (ESRR) – Vegetation Management

The Enhanced Service Reliability Rider (ESRR) includes the vegetation management expenditures associated with the transition from a performance-based reactive program to a five-year proactive, cycle-based trimming program. Under the program, trees and other vegetation, along the Company's circuits, are to be trimmed from end to end every four years, right-of-ways widened, and danger trees removed, among other directives. The program was expected to be complete in 2014.[127] In Case No. 13-2385-EL-SSO, the Company requested and the Commission

[126] AEP Ohio's response to 2016 Data Request 1-037.
[127] Case No. 11-346-EL-SSO, et. A., Order dated 8/8/13, page 64.

approved the continuation of the ESRR in order to complete the transition to a cycle-based vegetation management program through 2018.[128]

A unique project ID and work order combination identify the vegetation management program. The plant values for these assets are identified on a dollars-spent basis, and an allocation is conducted in order to remove only the incremental plant, as agreed to by the Company and Staff. The Company stated that this methodology is in line with the vegetation management rider to ensure that there is no double recovery of these assets.[129]

The Company excluded the following amounts for vegetation capital spend in the DIR that was recovered through the ESSR.

Table 7: Plant Vegetation Management Excluded from DIR by Filing

Period	Total	Less Depreciation	Amount Excluded
4th Quarter 2015	$ 35,028,528	$ (4,775,971)	$ 30,252,557
1st Quarter 2016	$ 35,005,506	$ (5,064,739)	$ 29,940,767
2nd Quarter 2016	$ 34,648,048	$ (5,351,913)	$ 29,296,135
3rd Quarter 2016	$ 35,920,523	$ (5,639,752)	$ 30,280,771
4th Quarter 2016	$ 38,095,425	$ (5,941,151)	$ 32,154,274

Blue Ridge compared the capital spend recovered through the ESRR to the amount excluded in the DIR to confirm there is no double recovery of these assets. The year-end 2016 ESRR filing workpaper includes the cumulative capital spent on vegetation management of $38,091,697.[130] The amount excluded in the DIR is $38,095,425 resulting in the DIR excluding $3,728 more than was recovered through the ESRR. The 2016 ESRR will be trued up in the fourth quarter of 2017.[131]

As previously discussed, Blue Ridge's transactional testing included a task to determine whether vegetation management charges were excluded from the DIR net plant investment.[132] Specifically, Blue Ridge reviewed the work order descriptions, associated project descriptions, and the FERC accounting to determine the nature of the work. Additional information was obtained to clarify projects and type of work being performed. The PowerPlant data extract query used to identify exclusions from the DIR was reviewed, as were the results provided within the DIR filings. Blue Ridge reviewed the sample work order description and the FERC accounts charged for any reference to vegetation management. Blue Ridge identified work orders W0027041 and W0025873 that represent part of the Forestry Program. The amounts included in the DIR represent the base line costs that are removed from the ESRR and appropriately included in the DIR.[133]

GridSMART

The Commission ordered that the DIR mechanism not include any gridSMART costs.[134] The gridSMART projects are separate from the DIR and are recovered through the gridSMART rider.

[128] Case No. 13-2385-EL-SSO, Opinion and Order dated February 25, 2015, pages 47–49.
[129] AEP Ohio's response to 2016 Data Request 1-039.
[130] AEP Ohio's response to 2016 Data Request 8-009.
[131] AEP Ohio's response to 2016 Data Request 8-009.
[132] WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix, T1c – Review work order to determine whether the work is related to Vegetation Management. If it is, are the costs excluded from the DIR?
[133] AEP Ohio's response to 2016 Data Request 6-005
[134] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 46.

The Company stated that costs related to the gridSMART rider are separately tracked by specific project ID and work orders.[135] These work orders are removed from the DIR.[136]

The Company excluded the following amounts for gridSMART Phase I from the DIR.

Table 8: gridSMART Net Plant Excluded from DIR by Filing

Period	Total	Less Depreciation	Amount Excluded
4th Quarter 2015	$ 26,514,286	$ (8,847,075)	$ 17,667,211
1st Quarter 2016	$ 26,368,056	$ (9,216,138)	$ 17,151,918
2nd Quarter 2016	$ 26,159,225	$ (9,490,212)	$ 16,669,013
3rd Quarter 2016	$ 25,915,607	$ (9,816,574)	$ 16,099,033
4th Quarter 2016	$ 25,691,428	$ (9,986,395)	$ 15,705,033

In the Company's DIR filings, the heading "gridSMART II Net Plant Adjustment (Recovered through GS Rider)" is mislabeled." The wording should have been "gridSMART I."[137] The Company stated that it neither removed any net plant associated with gridSMART Phase II nor recovered any costs associated with Phase II in 2016. The exclusion was to remove the net book value of the Phase I assets. [138]

The Company stated that all meters purchased in 2016 were for non-gridSMART purposes. All gridSMART Phase I meter purchases were completed in June 2010. Currently, the Company purchases AMI meters to replace the Phase I meters that may fail.[139]

The Phase I assets that are excluded are tagged in the Company's owned asset system in order to be removed from the DIR. The Phase I rider was based on capital dollars spent, not net book value, so there is no net book value comparison, and the Company cannot reconcile Net Book Value. The Company stated that it implemented a process that showed the amount of capital spent by work order for the Phase I project and compared that to the work orders included in the gridSMART net book value calculation in order to verify that all workorders were properly coded in the owned asset system and the assets associated with the capital being recovered through the Phase I rider was not also being recovered through the DIR.[140] Phase II of gridSMART will be implemented using a net book value calculation which is different from the way it was done in Phase I.[141]

In Case No. 13-2385-EL-SSO, as part of the Commission's extension of the DIR, the Commission approved the Company's request to include gridSMART Phase 1 capital costs in the DIR. The Company filed its final true-up of the Phase I project and will begin recovering the assets of the Phase I through the DIR per the Commission's order. This change was implemented beginning in April 2017. The DIR excluded the Net Book Value associated with the Phase I assets to reflect that the recovery of those assets was through the Phase I rider. In April 2017, the Company no longer adjusted the net book value associated with the Phase I assets from the DIR.[142]

[135] AEP Ohio's response to 2016 Data Request 1-040.
[136] AEP Ohio's response to 2016 Data Request 1-041.
[137] AEP Ohio's response to 2016 Data Request 8-008.
[138] AEP Ohio's response to 2016 Data Request 8-008.
[139] AEP Ohio's response to 2016 Data Request 1-034.
[140] AEP Ohio's response to 2016 Data Request 8-008.
[141] AEP Ohio's response to 2016 Data Request 8-008.
[142] AEP Ohio's response to 2016 Data Request 8-008.

With the approval of the gridSMART II stipulation in Case No. 13-1393-EL-RDR, the Company has placed its first order for AMI meters. AMI meters are booked to account 370.16. AMR meters are booked to account 370.[143] The Net Book Value associated with the Phase II assets that will be recovered through the Phase II rider will be removed from the DIR. The Phase II revenue requirement is calculated using the same methodology as the DIR. The carrying charges are applied to gross and net plant, which is different from the Phase I recovery, which was based on applying a levelized carring charge rate to dollars spent, not gross plant in service and net plant in service.[144] Since the recovery mechanisms for the DIR and gridSMART II are similar, the difficulties in reconciling to ensure there is no double recovery should be much easier.

As previously discussed, Blue Ridge's transactional testing included a task to determine whether gridSMART charges were excluded from the DIR net plant investment.[145] The work orders included in the work order sample are not new gridSMART. They represent regular meters and replacement gridSMART meters.[146]

Conclusion

In summary, Blue Ridge found the Company excluded capital additions recovered through other Commission-authorized riders from the DIR.

Accumulated Deferred Income Tax

The Commission ordered that the DIR mechanism account for accumulated deferred income tax (ADIT) offset. The Commission found that it is not appropriate to establish the DIR rate mechanism in a manner that provides the Company with the benefit of ratepayer-supplied funds. Any benefit resulting from ADIT should be reflected in the DIR revenue requirement.[147]

The DIR revenue requirement includes ADIT related to utility property of the distribution function.[148] The ADIT in the calculation of the DIR include direct-assigned amounts related to the distribution function.[149] The source of the data is the Company's utility property ADIT (Account 2821001) as reported in its balance sheet.[150] Blue Ridge reviewed the list of ADIT balances provided by the Company in Account 282 as of December 31, 2016.[151] Of the $694,575,485 total ADIT. Several line item descriptions were unclear as to the nature of the deferred tax. Additional information was obtained[152] and reviewed.[153] Blue Ridge found that the ADIT balances were related to utility property.

The Tax Increase Prevention Act of 2014 extended the 50% bonus tax depreciation for qualified property placed into service before January 1, 2015. The Protecting Americans from Tax Hikes Act of 2015 further extended the 50% bonus tax depreciation for qualified property placed in

[143] AEP Ohio's response to 2016 Data Request 1-034.
[144] AEP Ohio's response to 2016 Data Request 8-008.
[145] WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix, T1b.
[146] WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix, T1b.
[147] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 47.
[148] AEP Ohio's response to 2016 Data Request 1-027.
[149] AEP Ohio's response to 2016 Data Request 9-002.
[150] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 42.
[151] AEP Ohio's response to 2016 Data Request 1-026.
[152] AEP Ohio's response to 2016 Data Request 9-002.
[153] WP ADIT BR-DR-1-026_Attachment_1.xls.

service during 2015, 2016, and 2017. The Company claimed bonus tax deprecation on all eligible property placed in service. This bonus tax depreciation is reflected in the ADIT balances.[154]

The amount included is the incremental amount from date certain, August 31, 2010, as shown in the following table.

Table 9: Incremental ADIT Removed

Period	ADIT Amount	Incremental ADIT Offset
Date Certain 8/31/2010	$ 328,328,000	
4th Quarter 2015	$ 653,437,064	$ 325,109,064
1st Quarter 2016	$ 669,518,273	$ 341,190,273
2nd Quarter 2016	$ 685,973,055	$ 357,645,055
3rd Quarter 2016	$ 702,737,409	$ 374,409,409
4th Quarter 2016	$ 694,575,485	$ 366,247,485

The Company explained that the reduction in ADIT from the 3rd quarter 2016 ($702,737,409) to the 4th Quarter 2016 ($694,575,485) was primarily due to the recordation of the 2015 Tax Return True-up adjustments. Bonus Tax depreciation on the 2015 tax return was lower than accrued due to plant additions being lower than forecasted.[155]

Blue Ridge found that the ADIT as of December 31, 2016, was related to utility plant and that incremental ADIT was appropriately excluded from the change in Distribution Plant before applying the return component of the carrying charge.

CARRYING CHARGE RATE

The carrying charge includes elements to allow the Company an opportunity to recover property taxes and depreciation and to earn a return (and associated income taxes) on plant in service associated with distribution net investment.

The return, depreciation, and property tax components are separate components in the DIR calculation. The following table summarizes the components for the carrying charge rate.

Table 10: Carrying Charge Rate - Components

Description	2016
Return - Pre-Tax WACC	10.54%
Average Depreciation Rate	3.68%
Weighted Average Property Tax	5.66%
Carrying Charge Rate	19.88%

Pre-Tax Weighted Average Cost of Capital (WACC)

The carrying charge rate includes a pre-tax weighted average cost of capital (WACC). The Commission approved the capital structure and percentage cost for debt and common equity in Case No. 13-2385-EL-SSO.[156] The following table shows the derivation of the pre-tax WACC.

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[154] AEP Ohio's response to 2016 Data Request 1-028.
[155] AEP Ohio's response to 2016 Data Request 9-001.
[156] Case No. 13-2385-EL-SSO, pages 83-84, AEP Ohio response to 2015 Data Request 10-001, and AEP Ohio response to 2015 Data Request 1-030.

Table 11: Pre-Tax Weighted Average Cost of Capital

Description	% of Total Capital	Embedded Cost	Revenue Tax Conversion	Pre-Tax WACC
Long Term Debt	52.54%	6.05%	1.000000	3.18%
Common Stock	47.56%	10.20%	1.385870	7.36%
Total	100.10%			10.54%

The WACC is applied to the adjusted change in net Distribution Plant to derive the return component of the Carrying Charge. Blue Ridge found that the amount is not unreasonable.

Average Depreciation Expense

The Company has used 3.68% for the depreciation rate component of the carrying charge rate. The rate is the combined Company's average distribution plant depreciation rate approved in the last distribution rate case (No. 11-351-EL-AIR et al. Settlement).[157] All FERC accounts included for recovery in the DIR use Commission-approved depreciation rates.[158] The Company made no changes to its depreciation accrual rates in 2016.[159]

The Company stated that a depreciation study was performed for Ohio Power on the plant in service balances as of December 31, 2015, and filed with the Public Utilities Commission of Ohio staff on November 21, 2016. The depreciation study was filed to comply with the order in Case No. 13-2385-EL-SS and Case No. 13-2386-EL-AAM, in which the Commission adopted the Staff's recommendation to require that Ohio Power file an updated depreciation study by November 2016. No depreciation rates were updated for Ohio Power as a result of the depreciation study that was filed with the Public Utilities Commission of Ohio Staff.[160]

The depreciation rate is applied to the adjusted change in gross Distribution Plant to derive the depreciation expense component of the Carrying Charge. The depreciation expense is not unreasonable.

Weighted Average Property Tax

The carrying charge rate property tax component is based upon the property taxes from the test year data from the Company's Application in the base distribution case in Case No. 11-351-EL-AIR.[161] In the DIR filings under review in this audit, the Company used the property tax rate of 5.66%, consistent with prior DIR filings. Blue Ridge found the rate not unreasonable.

For the purpose of calculating property taxes, the Company applied the property tax rate to the adjusted change in Distribution Plant. The adjusted change in Distribution Plant includes an adjustment to reflect the Commission's adoption of OCC's recommendation from Case No. 13-2385-EL-SSO to include an adjustment to eliminate the cumulative amortization of the excess depreciation reserve since December 31, 2011 (when rates in Case Nos 11-351-EL-AIR and 11-352-EL-AIR went into effect). The property tax is not unreasonable.

Conclusion

In summary, Blue Ridge found that the carrying charge rate is not unreasonable.

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[157] Case No. 11-351-EL-AIR, Settlement dated November 21, 2011, Attachment D.
[158] AEP Ohio's response to 2016 Data Request 1-025.
[159] AEP Ohio's response to 2016 Data Request 1-023.
[160] AEP Ohio's response to 2016 Data Request 1-024.
[161] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 45..

Gross-Up Factor (CAT)

The Rider Revenue Requirements were grossed up for the Commercial Activity Tax (CAT). The Company used the statutory rate of 0.26% for the Commercial Activity Tax as defined in Section 5751.03 of the Ohio Revised Code.[162] Blue Ridge found the rate not unreasonable.

Revenue Offset

The Commission ordered that the DIR revenue requirement be increased to reflect a $62.344 million revenue credit included in the November 23, 2011, distribution case settlement.[163] The revenue credit will prevent excess collection of distribution revenue associated with collections from the DIR.[164] At the time the distribution case was settled, the Company had a pending proceeding that included a DIR mechanism. The credit is derived from subtracting $23.656 million of DIR revenue related to certain post-date distribution investments, actual and estimated through December 2012, from the $86 million DIR cap for 2012 in the ESP II Stipulation.[165]

The $62.344 million provided the mechanism to recover a portion of distribution costs that the Company incurred during the test year in the base rate case. The Company argued, "Failure to adjust the DIR to reflect the revenue credit in the distribution case would deprive the Company an opportunity to recover costs prudently incurred during the test year."[166]

Blue Ridge found that the Company appropriately increased the DIR revenue requirement by the $62.344 million revenue credit included in the distribution case settlement in Case No. 11-351-EL-AIR.

Annual Cap and Over/Under Recovery

Annual Cap

In Case No. 11-346-EL-SSO, the recovery on the DIR was capped at $86 million in 2012, $104 million for 2013, $124 million for 2014, and $51.7 million for the period January 1 through May 31, 2015, for a total of $365.7 million. The DIR was to expire on May 31, 2015.[167] In a Second Entry on Rehearing in Case No. 13-2385-EL-SSO, the Commission authorized revenue caps for the DIR to be set at $145 million for 2015 (including amounts previously authorized in the *ESP 2 Case*), $165 million for 2016, $185 million for 2017, and $86 million for January through May 2018.[168]

For any year that the Company's investment would result in revenues collected which exceed the cap, the overage would be recovered and be subject to the cap in the subsequent period. Symmetrically, for any year that the revenue collected under the DIR is less than the annual cap allowance, the difference would be applied to increase the cap for the subsequent period.[169] The over/under recovery balance from the previous quarter is added or subtracted to get the fully adjusted revenue requirement.

[162] AEP Ohio's response to 2016 Data Request 1-031.
[163] Case No. 11-346-EL-SSO, et al., Order dated 8/8/12, page 43.
[164] Case No. 11-351-EL-AIR, et al., Order dated 12/14/11, page 5.
[165] Case No. 11-351-EL-AIR, et al., Order dated 12/14/11, page 5, item (g).
[166] Case No. 11-346-EL-SSO, et al., Direct Testimony of William A. Allen, page 11, lines 3-5.
[167] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 43.
[168] Case No. 13-2385-EL-SSO, et al., Second Entry on Rehearing dated May 28, 2015, page 24.
[169] Case No. 11-346-EL-SSO, et al., Order dated August 8, 2012, page 43.

Blue Ridge found that the Company did not exceed the $165 million cap for 2016 when adjusted for the over/under recovery for previous years. The annual cap under recovery to be carried forward is $18,459,078 as shown in the following table:

Table 12: Rider DIR Annual Cap (Over) / Under Recovery

Period	Annual Cap	Cap Adjusted with (Over)/Under	Revenue Requirement	(Over)/Under
2012	$ 35,833,333	$ 35,833,333	$ 29,131,148	$ 6,702,185
2013	$ 104,000,000	$ 110,702,185	$ 87,203,726	$23,498,459
2014	$ 124,000,000	$ 147,498,459	$120,575,764	$26,922,695
2015	$ 145,000,000	$ 171,922,695	$149,265,024	$22,657,671
2016	$ 165,000,000	$ 187,657,671	$169,198,593	$18,459,078

Note: 2012 Annual Cap of $86 million prorated for August through December

Of note in future DIR filings, after the Commission has reviewed and reconciled the gridSMART Phase I costs, the Company may transfer the approved capital costs balance into the DIR. These transferred gridSMART Phase 1 costs will not be subject to the DIR caps.[170]

DIR Costs vs. Amount Billed Under/Over Recovery

The Company also calculates the amounts over collected or under collected. The Company compares the DIR revenue requirement to the DIR revenue billed[171] through the same time period. The revenue requirement is figured monthly through a run of the DIR calculation based on DIR plant added each month. Any difference is shown as an over or under recovery and the rate is adjusted quarterly.[172] The 2016 DIR Costs vs. DIR Billed showed an over-collected balance. However, the since-inception DIR costs as compared to the DIR billed shows an under recovery as presented in the following table:

Table 13: DIR Costs vs. DIR Billed - 2016 and Since Inception

Description	2016	Since Inception
DIR Revenue Requirements	$ 169,198,593	$ 555,374,255
DIR Revenues Billed	$ 176,277,174	$ 547,657,800
Over / (Under) Billed	$ 7,078,581	$ (7,716,455)

The DIR costs used to calculate the over/(under) billing is based on the recognized earnings on the amount of the DIR investment beginning with its initial approval in Case No. 11-346-EL-SSO. The amount is based upon 1/12 of the annual revenue requirement calculated monthly based on a life-to-date balance of the previous month balance of distribution plant compared to the distribution net plant as of August 31, 2010.[173]

[170] Case No. 13-2385-EL-SSO, Opinion and Order dated February 25, 2015, page 52.
[171] The Company assumes for purposes of the DIR calculation that Billed DIR amounts equal revenues received.
[172] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," pages 45-46.
[173] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 46

The DIR revenue is tracked as a separate billing rider and is obtained directly from the Company's billing system. The DIR revenue is based on the net distribution plant balances from the prior month since plant account balances are available on a one-month lag.[174]

Even though the DIR is filed and the tariff is calculated quarterly, the Company calculates the over or under billed based on a monthly change in revenue requirements. The Company explained that the Commission's true-up mechanism allows for recovery of actual costs based upon net distribution plant balances placed in service. The calculation is performed monthly to identify the net distribution plant balances as the investment is placed in service.[175]

Blue Ridge found that the Company's methodology for calculating the over or under billed for the DIR was not unreasonable.

ANNUAL BASE DISTRIBUTION REVENUE

The rider is collected as a percentage of base distribution revenue. The annual base distribution revenue for DIR filing for the four quarters in 2016 is provided in the following table.

Table 14: Annual Base Distribution Revenues in DIR by Quarter

Period	Supporting Documentation	Ohio Power Rate Reactive Demand (RD06)	Adjusted	Amount Included in DIR
4th Quarter 2015	$ 633,702,536	$ -	$ 633,702,536	$ 633,702,536
1st Quarter 2016	622,496,816	-	622,496,816	622,496,816
2nd Quarter 2016	618,165,729	377,155	617,788,574	617,788,574
3rd Quarter 2016	629,933,971	385,995	629,547,976	629,547,976
4th Quarter 2016	634,624,483	-	634,624,483	634,624,483

Annual base distribution revenues are obtained through the Company's billing system. The billing system tracks each charge by an equation code. The base distribution revenues are represented by a unique set of equation codes that allow them to be separately identified.[176] Blue Ridge compared the screen shots of the query used to determine the base distribution revenues[177] to the amount included within the DIR filings. The 2nd and 3rd quarter DIR filings' base distribution revenue inappropriately excluded the reactive demand of Ohio Power rate zone only (RD06). The RD06 reflects the naming convention of the equations that calculate charges in AEP's billing system. The RD06 represents the reactive demand charge that is part of the base revenue collected from GS4 customers.[178] The exclusion of the reactive demand of Ohio Power rate zone from the Annual Base Distribution Revenues, resulted in the overstatement of Percentage of Base Distribution Revenue reported in the 2nd and 3rd quarter 2016. The following table summarizes the differences between the as filed and the corrected amounts.

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[174] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 46

[175] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 46.

[176] Blue Ridge's Report dated June 19, 2013, titled "Compliance Audit of 2012 Distribution Investment Rider (DIR) of Columbus Southern Power and Ohio Power Company d/b/a AEP Ohio," page 46.

[177] Ohio Power response to Data Request 1-046.

[178] Ohio Power response to Data Request 7-006.

Table 15: Correction of Understated Base Distribution Revenue on DIR

		As Filed		Corrected		Difference
Period	Fully Adjusted Revenue Requirement	Annual Base Distribution Revenue	Percentage of Base Distribution Revenue DIR Charge	Annual Base Distribution Revenue	Percentage of Base Distribution Revenue DIR Charge	Percentage of Base Distribution Revenue DIR Charge
1st Quarter 2016	181,352,136	622,496,816	29.13302%	622,496,816	29.13302%	0.00000%
2nd Quarter 2016	185,120,691	617,788,574	29.96506%	618,165,729	29.94677%	-0.01828%
3rd Quarter 2016	182,490,199	629,547,976	28.98750%	629,933,971	28.96973%	-0.01776%
4th Quarter 2016	188,957,747	634,624,483	29.77473%	634,624,483	29.77473%	0.00000%

Blue Ridge reviewed the impact to the DIR revenue and found that the over/under calculation corrected the impact of the overstated DIR ratio. The over/under calculation is based on the calculated revenue requirements not the DIR ratio.

Conclusion

In conclusion, the mathematical calculations of the DIR revenue requirements for each quarter are not unreasonable. However, Blue Ridge found that the 2nd and 3rd quarter DIR filing's base distribution revenue inappropriately excluding the reactive demand of Ohio Power rate zone (RD06) resulted in an overstated AEP Ohio Percentage Base Distribution Revenue. Blue Ridge reviewed the impact to the DIR revenue and found that the over/under calculation corrected the impact of the overstated DIR ratio.

In addition, Blue Ridge had several findings and recommendations related to several of the components of the DIR revenue requirements that could impact the amount that should be recovered through the DIR. These findings included cost elements that are not an appropriate overhead charge for distribution plant and an overstated Standard Fringe Factor. Blue Ridge has included recommendations to address these concerns.

Overall Impact of Findings on Rider DIR Revenue Requirements

Blue Ridge's review of the accounting, accuracy, prudency, and compliance of Ohio Power Company with its Commission-approved DIR found three issues that require computation by the Company to determine the impact on the DIR.

First, several work orders within the sample reviewed by Blue Ridge included cost elements totaling $138,511 related to costs that are inappropriate for inclusion in the distribution rider. While the $138,511 observed by Blue Ridge would be immaterial to the Company's DIR, it is likely that these cost elements are included within other work orders included within the overall work order population and are, therefore, being recovered through the DIR. Blue Ridge extrapolated the value of the cost elements found in the sample to the population of work orders, resulting in an extrapolated total of $353,207. Blue Ridge extrapolated the finding to the increase in net distribution plant since August 31, 2010, and estimates net distribution plant could be overstated by approximately $1.7 million. Blue Ridge recommends that the Company review the cost detail for the total population of work orders included in the DIR and remove the costs of the following five identified cost elements from the DIR.

1. Cost Element 141: Incentive Accrual Dept. Level—used to record Distribution, Customer Operations and Regulatory Services Incentive Plan expense
2. Cost Element 143: Other Lump Sum Payments
3. Cost Element 145: Stock-based compensation—used to record Performance Share Incentive expense

4. Cost Element 154: Restricted Stock Incentives—used to record Restricted Stock Unit expense
5. Cost Element 155: Transmission Incentives—used to record Transmission Incentive Plant expense

Second, Blue Ridge's review of the standard costs components found that the Standard Fringe Factor is overstated by approximately 15 percent. As this rate is used for the capitalization of meter and line transformer installations and removal costs, its overstatement results in an overstatement in these capital amounts. The Company is developing an analysis of the impact and will provide it later. Blue Ridge recommends that the Company calculate the impact and adjust the DIR.

APPENDICES

Appendix A: Rider DIR Excerpts within Stipulations and Order (and electronic copies on disc of prior audit reports and filings reviewed)

Appendix B: Abbreviations and Acronyms

Appendix C: Data Requests and Information Provided

Appendix D: Work Papers

Appendix A: Rider DIR Excerpts within Order and Combined Stipulation

Excerpts from the Commission Opinions and Orders specifically related to Rider DIR are provided below.

Case No. 11-351-EL-AIR, et al. Opinion and Order dated December 14, 2011

On page 4-6

(1) The outcome of the provisions in the Stipulation will result in a zero base distribution rate increase (Joint Ex. 1 at 3).

(a) The value of CSP's property which is used and useful in the rendition of distribution of electric power, or rate base, is $908,001,000, and the current operating income is $65,194,000, resulting in a rate of return of 7.18 percent (Id. at 4, Stipulated Schedule A-1).

(b) The value of OPCo's property which is used and useful in the rendition of distribution of electric power, or rate base, is $1,003,670,000, and the current operating income is $55,763,000, resulting in a rate of return of 5.56 percent (Id. at 4-5, Stipulated Schedule A-1).

...

(e) CSP and OPCo are entitled to returns on equity of 10.0 percent and 10.3 percent, respectively (*Id*.).

...

(g) In order to prevent excess collection of distribution revenue associated with collection of the Distribution Investment Rider (DIR) sought in the September 7, 2011, Stipulation filed in In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO (ESP II Stipulation), a $62,344,000 revenue credit shall be applied as outlined by the terms of this Stipulation. This credit shall be derived from subtracting $23,656,000 of DIR revenues related to certain postdate distribution investments, actual and estimated, through December 2012, from the $86,000,000 DIR cap for 2012 in the ESP II Stipulation. (Id. at 6.)

(h) The first $46,656,000 of DIR revenue credit will negate the base distribution revenue requirement stated above, resulting in a net $0 base distribution rate increase until such rates may be established pursuant to an application for establishing rates filed under Section 4909.18, Revised Code. The remaining $15,688,000 DIR revenue collected will be applied annually through May 31,2015, as follows:

(i) The first $14,688,000 of remaining DIR revenue credit will be applied solely to residential customers through a new Commission-approved rider during the term in which the DIR is in effect through May 31, 2015. The total credit to residential customers' bills during this term will be no greater than $50,184,000.

(ii) The final $1,000,000 DIR annual revenue credit will be used to fund the Partnership with Ohio Initiative, totaling $3,400,000 during the term in which the DIR is in effect. This low-income bill payment assistance funding will be provided through the Partnership with Ohio Initiative's existing Neighbor-to-Neighbor program. (Id. at 6-7.)

(2) The zero base distribution rate increase includes amortization of the depreciation reserve over-accrual identified in the Staff reports. The schedule will reflect a ten-year amortization of the theoretical accumulated depredation reserve over-accrual; however, in recognition of the overall

compromises in this Stipulation, AEP-Ohio will amortize the depreciation reserve over-accrual over a seven-year period. (Id. at 7-8.)

(3) AEP-Ohio will be authorized to establish new depreciation rates based on the whole-life method as recommended by the Staff reports, and, if the merger of CSP and OPCo is approved, the combined company will utilize the combined rates detailed in Attachment D to the Stipulation (Id. at 8).

On page 7-8

(9) AEP-Ohio will include data related to its DIR investments and their effect on distribution service reliability in its next application(s) to 11-351-EL-AIR, et al. establish new service standards under Rule 4901:1-10-10, Ohio Administrative Code (O.A.C.) (Id. at 10-11).

On page 10

Finally, the Commission finds that, with respect to the third criterion, the evidence in the record demonstrates that the Stipulation does not violate any important regulatory principle or practice (Co. Ex. 4 at 12; OCC Ex. 1 at 8-9). The Commission notes that the Stipulation eliminates any potential for double recovery of distribution investments through distribution base rates and the distribution investment rider (DIR) provided for by AEP-Ohio's electric security plan in In re Columbus Southern Power Company and Ohio Power Company, Case Nos. 11-346-EL-SSO, et al. (Co. Ex. 4 at 5).

Case No. 11-351-EL-AIR Approved Settlement Agreement

On pages 4-7

1) AEP Ohio's rate base, rate of return, and recommended revenue requirement shall be as set forth on the Revised Schedules, attached as Attachment A, which are herby incorporated by reference. Specifically, the Revised Schedules modify the Staff Report Schedules in the following respects:

a. The value of CSP's property used and useful in the rendition of distribution of electric power (rate base) is $908.001 million Stipulated Schedules A-1 and B-1).

b. The value of OPCo's property used and useful in the rendition of distribution of electric power (rate base) is $1,001670 million (Stipulated Schedules A-1 and B-1).

...

i. CSP is entitled to an overall rate of return of 7.78%, reflecting a cost of long- term debt 5.50%, a cost of preferred stock of 0.0%, and a return on equity of 10.00%.

j. OPCo is entitled to an overall rate of return of 7.97%, reflecting a cost of long-term debt 5.27%, a cost of preferred stock of 4.40%, and a return on equity of 10.30%.

k. The Signatory Parties agree that for purposes of this Stipulation reached in these cases the return on equity (ROE) used for CSP is 10.0% and for OPCo the ROE used is 10.3% and the ROE used for the combined CSP and OPCo if the merger is approved is 10.2%.[179]

2) The Signatory Parties agree that the increase in the distribution base rate revenue requirement of $46.656 million shall terminate on May 31, 2015. Any change to distribution base

[179] The establishment of the ROE in these cases does not preclude Signatory Parties from arguing in other AEP Ohio cases that this authorized ROE is not an appropriate component of a proposed carrying charge.

rates upon expiration of the rates agreed to in this Stipulation shall occur pursuant to an application for establishing rates filed under R C 4909.18

3) The Signatory Parties agree that in order to prevent any potential excess collection of distribution revenue associated with the collection of the DIR in the ESP II Stipulation, there will be a $62.344 million revenue credit applied, as outlined in this Stipulation. This credit is derived from taking the $86 million DIR cap for 2012 in the ESP II Stipulation[180] and subtracting the $23.656 million of DIR revenues related to post date certain distribution investments actual and estimated through December 2012 (Attachment R). This establishes the pre date certain distribution investment during the period from January 2000 through August 2010 that is eligible to be collected through the DIR through the ESP II Stipulation

4) The first $46.656 million of DIR revenue credit will be treated on the revised CSP and OPCo Schedules A-1 as a credit to negate the aforementioned base distribution revenue requirement, resulting in a net $0 base distribution rate increase until new base distribution rates are established pursuant to an application for establishing rates filed under R C 4909.18.

The remaining $15.688 million DIR revenue collected will be applied annually through May 31, 2015 as follows:

a) The first $14.688 million of remaining DIR revenue credit will be applied annually as a credit solely to residential customers though a new Commission approved rider[181] during the term in which the DIR is in effect, until May 31, 2015.[182] The total credit to Residential customers' bills during the term in which the DIR is in effect will be no greater than $50.184 million [$14 .688 million annually divided by 12 (months) times 41 (months)]

b) The final $1 million DIR annual revenue credit will be used to fund the Partnership with Ohio initiative, prorated for 2015, totaling $3.4 million during the term in which the DIR is in effect. This low-income bill payment assistance funding shall be provided through the Partnership with Ohio Initiative's existing Neighbor to Neighbor program The Companies will provide Staff, APJN and OCC an annual verification of the credit disbursement

5) The determination of the zero base distribution increase in this Stipulation includes amortization of the depreciation reserve over accrual identified in the Staff Reports of investigation in these cases6 The Parties agree that the Stipulated A-1 schedules in Attachment A will reflect a 10 year amortization of the theoretical accumulated depreciation reserve over-accrual However, in recognition of the overall compromises in this settlement agreement and in particular the decrease in carrying charges on the DARR regulatory assets that is to occur once DARR collection has begun, the Companies will amortize the depreciation reserve over-accrual over a 7 year period. In addition, AEP Ohio will provide the Commission Staff with a yearly comparison of the theoretical depreciation reserve with the actual depreciation reserve balance.

6) In determination of the zero distribution base revenue increase, the Signatory Parties agree that AEP Ohio will be authorized to establish new depreciation rates based on the whole life method as recommended in the Staff Reports of Investigation.[183] If the merger of CSP and OPCo is approved, the combined Company will utilize the combined rates detailed in Attachment D.

…

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[180] ESP II Stipulation at 9.
[181] This residential credit will be a rider applied on a percentage of base distribution charges basis.
[182] The DIR will end on may 31, 2015. ESP II Stipulation at 9.
[183] Staff Reports at 6.

On page 12

J) The Signatory Parties agree that the Stipulation in these cases is intended to settle only the issues in the cases listed on the caption of this Stipulation. While the terms of the agreement address the collection of distribution investment associated with the Distribution Investment Rider sought in the Stipulation filed in Commission Cases 11-346-EL-SSO and 11-348-EL-SSO et al., a signature by a party to this agreement does not in any way change the position or opinion of that party in those other cases Signatory Parties to these cases are only agreeing on how to treat the collection of distribution investment if the Commission approves the DIR mechanism as proposed in the ESP II Stipulation before the Commission.[184] The Commission approval of the DIR in the ESP II case is linked to this agreement as a prerequisite to the elements of the bargain reached in these proceedings. Therefore, to the extent the Commission materially modifies the DIR in the ESP II to the detriment of AEP Ohio then AEP Ohio has the right to withdraw from this agreement and litigate the issues as if the settlement in these cases had not been reached. AEP Ohio must exercise this right no later than thirty (30) days of the final non-appealable order in the ESP II proceeding. If the Commission increases the amount of the DIR in the ESP II Stipulation to the detriment of another Signatory Party, then that Signatory Party has the right to withdraw from this agreement and litigate the issues as if the settlement in these cases had not been reached; the Signatory Party seeking this withdrawal must exercise this right no later than thirty (30) days of the final non-appealable order in the ESP II proceeding In addition, in the event the DIR is approved but not implemented this Stipulation will be null and void and the issues in this case will be litigated as if the settlement in these cases had not been reached.

Case No. 11-346-EL-SSO, et al. Opinion and Order dated August 8, 2012

On pages 42-47

9. Distribution Investment Rider

The Company's modified ESP application includes a Distribution Investment Rider (DIR), pursuant to the provisions of Section 4928.143(B)(2)(h) or (d), Revised Code, and consistent with the approved settlement in the Company's distribution rate case,[185] to provide capital funding, including carrying cost on incremental distribution infrastructure to support customer demand and advanced technologies. Aging infrastructure, according to AEP-Ohio, is the primary cause of customer outages and reliability issues. AEP-Ohio reasons that the DIR will facilitate and encourage investments to maintain and improve distribution reliability, align customer expectations and the expectations of the distribution utility, as well as streamline recovery of the associated costs and reduce the frequency of base distribution rate cases. Replacement of aging distribution equipment will also support the advanced technologies of gridSMART which will reduce the duration of customer outages based on preliminary gridSMART Phase 1 information. The Company argues that its existing capital budget forecast includes an annual investment in excess of $150 million plus operations and maintenance in distribution assets. The DIR mechanism, as proposed by the Company, includes components to recover property taxes, commercial activity tax, and to earn a

[184] OCC and APJN were not signatory parties to the ESP II Stipulation. Although participating in this Stipulation as Signatory Parties, OCC's and APJN's participation here shall not be construed as a waiver or compromise of their respective positions taken in the ESP II cases in which *inter alia*, OCC and APJN continue to advocate against the inclusion of a DIR as part of the Companies' ESP.
[185] In re AEP-Ohio, Case Nos. 11-351-EL-AIR, et al. Opinion and Order at 5-6 (December 14, 2011) in reference to paragraph IV.A.3 of the Joint Stipulation and Recommendation filed on November 23, 2011.

return on plant in-service based on a cost of debt of 5.46 percent, a return on common equity of 10.2 percent utilizing a 47.72 percent debt and 52.28 percent common equity capital structure. The net capital additions to be included in the DIR reflect gross plant in-service after August 31, 2010, as adjusted for accumulated depreciation, because August 31, 2010, is the date certain in the Company's most recent distribution rate case and any increase in net plant that occurs after that date is not recovered in base rates. The Company proposes to cap the DIR mechanism at $86 million in 2012, $104 million for 2013, $124 million for 2014 and $51.7 million for the period January 1 through May 31, 2015, for a total of $365.7 million. As the DIR mechanism is designed, for any year that the Company's investment would result in revenues to be collected which exceed the cap, the overage would be recovered and be subject to the cap in the subsequent period. Symmetrically, for any year that the revenue collected under the DIR is less than the annual cap allowance, then the difference shall be applied to increase the cap for the subsequent period. The Company notes that the DIR revenue requirement must recognize the $62.344 million revenue credit reflected in the Commission approved Stipulation in the Company's distribution rate case.[186] As proposed by the Company, the DIR would be adjusted quarterly to reflect in-service net capital additions, excluding capital additions reflected in other riders, and reconciled for over and under recovery. The Company specifically requests through the DIR project, that when meters are replaced by the installation of smart meters, that the net book value of the replaced meter be included as a regulatory asset for recovery in a future filing. The DIR mechanism would be collected as a percentage of base distribution revenues. Because the DIR provides the Company with a timely cost recovery mechanism for distribution investment, AEP-Ohio will agree not to seek a change in distribution base rates with an effective date earlier than June 1, 2015. (AEP-Ohio Ex. 116 at 9-12; AEP-Ohio Ex. 110 at 18-19.)

The Company notes that Staff continuously monitors the Company's distribution system reliability by way of service complaints, electric outage reports and compliance provisions pursuant to Chapter 4901:1-10, O.A.C. In reliance on Staff testimony, the Company offers that the reliability of the distribution system was evaluated as a part of this case. (Staff Ex. 106 at 5-6; Tr. at 4339,4345-4346.)

Customer expectations, as determined by AEP-Ohio, are aligned with the Company's expectations. AEP-Ohio witness Kirkpatrick offered that the updated customer survey results show that 19 percent of residential customers and 20 percent of commercial customers expect their reliability expectations to increase in the next five years. AEP-Ohio points out that when those customers are considered in conjunction with the customers who expect the utility to maintain the level of reliability, customer expectations increase to 90 percent of residential customers and 93 percent of commercial customers. AEP-Ohio states it is currently evaluating, based on several criteria, various asset categories with a high probability of failure and will develop a DIR program, with Staff input, taking into consideration the number of customers affected. (AEP-Ohio Ex. 110 at 11-19.)

OHA supports the adoption of the DIR as proposed by the Company (OHA Br. at 2). Kroger, OCC and APJN, on the other hand, ask the Commission to reject the DIR, as this case is not the proper forum to consider the recovery of distribution-related costs. Kroger, OCC and APJN reason that prudently incurred distribution costs are best considered in the context of a base distribution rate case where such cost are more thoroughly reviewed by the Commission. Kroger asserts that maintaining the distribution system is a fundamental responsibility of the utility and the Company should continue to operate under the terms of its last distribution rate case until the next such

186 *Id.*

proceeding. If the Commission elects to adopt the DIR mechanism, Kroger endorses Staffs position that the DIR be modified to account for accumulated deferred income taxes (ADIT) and accelerated tax depreciation. In addition, Kroger asserts that the DIR for the CSP rate zone and the OP rate zone are distinct and the cost of each unique service area should be maintained and the distribution costs assigned on the basis of cost causation. OCC and APJN add that the Company's reason for pursuing the DIR, as a component of the ESP rather than in the distribution case, is the expedience of cost recovery and when that rationale is considered in conjunction with the lack of detail on the projects to be covered within the DIR, suggest that the DIR is not needed. (Kroger Ex. 101 at 13-19; Kroger Reply Br. at 3-4; OCC/APJN Br. at 87-89; Tr. at 1184.)

OCC and APJN argue that in determining whether the DIR complies with the requirements of Section 4928.143(B)(2)(h), Revised Code, the Company focuses exclusively on the percentage of residential and commercial customers (71 percent and 73 percent, respectively) who do not believe that their electric service reliability expectations will increase rather than the minority of customers who expect their service reliability expectations to increase (19 percent and 20 percent, respectively). OCC and APJN note that 10 percent of residential customers and seven percent of commercial customers expect their reliability expectations to decrease over the next five years. At best, these interveners assert, the customer survey results are inconclusive regarding an expectation for reliability improvements as the majority of customers are content with the status quo. OCC and APJN state that with the lack of project details, and without providing an analysis of customer reliability expectation alignment with project cost and performance improvements, AEP-Ohio has failed to meet its burden of proof to support the DIR. Accordingly, OCC and APJN request that this provision of the modified ESP be rejected. (AEP-Ohio Ex. 110 at 11-12; OCC/APJN Br. at 987-994).

NFIB and COSE emphasize that the DIR, as AEP-Ohio witness Roush testified, would, if approved as proposed, result in General Service tariff rate customers receiving an increase of approximately 14.2 percent in distribution charges, about $2.00 monthly (NFIB/COSE Br. at 8-9;Tr. at 1162-1163).

Staff testified that consistent with the requirements of Rule 4901:1-10-10(B)(2), O.A.C., AEP-Ohio has rate zone specific minimum reliability performance standards, as measured by the customer average interruption duration index (CAIDI) and system average interruption frequency index (SAIFI).[187] According to Staff, development of each CAIDI and SAIFI takes into account the electric utility's three-year historical system performance, system design, technological advancements, the geography of the utility's service territory, customer perception surveys and other relevant factors. Staff monitors the utility's compliance with the reliability standards. Staff offers that based on customer surveys, 75 to 80 percent of residential and commercial customers are satisfied overall with the Company's service reliability. However, the Company's 2011 reliability measures were below their reliability measures for 2010 for CSP and the SAIFI measure was worse in 2011 than in 2010 for OP. Accordingly, Staff determined that AEP-Ohio's reliability expectations are not currently aligned with the reliability expectations of its customers. Staff further offered that a number of conditions be imposed on the Commission's approval of the DIR, including that the Company be ordered to work with Staff to develop a distribution capital plan, that the DIR mechanism include an offset for ADIT, irrespective of the Company's asserted inconsistency with the distribution rate case settlement, and that gridSMART related cost not be recovered through the DIR, so as to better facilitate the tracking of gridSMART expenditures and savings and benefits of the gridSMART project. Further, Staff proposes that AEP-Ohio be directed to make quarterly filings

[187] See *In re AEP-Ohio*, Case No. 09-756-EL-ESS, Opinion and Order (September 8, 2010).

to update the DIR mechanism, with the filed rate to be effective, unless suspended by the Commission, 60 days after filing. The DIR mechanism, as advocated by Staff, would be subject to annual audits after each May filing and, in addition, subject to a final reconciliation filing on or about May 31, 2015. With the final reconciliation, Staff recommends that any amounts collected by AEP-Ohio in excess of the established cap be refunded to customers as a one-time credit on customer bills. (Staff Ex. 106 at 6-11; Staff Ex. 108 at 3-4; Tr. at 4398.)

AEP-Ohio disagrees with the Staff's rationale that the Company's and customer's expectations are not aligned. The Company reasons that the Staff relies on the reliability indices and the fact that the Company performed below the level of the preceding year. AEP-Ohio notes that in the most recent customer survey results, with the same questions as the prior year, the Company received an 85 percent positive rating from residential customers and a 92 percent positive rating from commercial customers for providing reliable service. Further, AEP-Ohio points out that missing one of the eight applicable reliability standards during the two year period does not, under the rules, constitute a violation. The Company also notes that the reliability standards are affected by storms, which are not defined as major storms, and other factors like tree-caused outages. (Tr. at 4344-4345, 4347, 4366-4367; OCC Ex. 113, Att. JDW-2.)

AEP-Ohio also opposes Staff's recommendation to file the DIR plan in a separate docket, subject to an adversarial proceeding. The Company expresses great concern that this recommendation, if adopted, will result in the Commission micromanaging and becoming overly involved in the "day-to-day operations of the business units within the utility."

As to Staff's and Kroger's proposal to reduce the DIR to account for ADIT, the Company responds that such an adjustment would have resulted in a reduced DIR credit if taken into account when the distribution rate case settlement was pending. AEP-Ohio argues that the decision on the DIR in the modified ESP should continue to mirror the understanding of the parties to the distribution rate case as any change would improperly impact the overall balanced ESP package. (AEP-Ohio Ex. 151 at 9-10.)

As authorized by Section 4928.143(B)(2)(h), Revised Code, an ESP may include the recovery of capital cost for distribution infrastructure investment to improve reliability for customers. A provision for distribution infrastructure and modernization incentives may, but need not, include a long-term energy delivery infrastructure modernization plan. We find that the DIR is an incentive ratemaking to accelerate recovery of the Company's investment in distribution service. In deciding whether to approve an ESP that contains any provision for distribution service. Section 4928.143(B)(2)(h), Revised Code, directs the Commission, as part of its determination, to examine the reliability of the electric utility's distribution system and ensure that customers' and the electric utility's expectations are aligned and that the electric utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

In this modified ESP, there is some disagreement between Staff and the Company whether or not AEP-Ohio's reliability expectations are aligned with the expectations of its customers. The Company focuses on customer surveys to conclude that expectations are aligned while Staff interprets the slight degradation in the reliability performance measures to indicate that expectations are not aligned. Despite the different conclusions by the Company and Staff, the Commission finds that both Staff and the Company have demonstrated that indeed, customers have a high expectation of reliable electric service. Given that customer surveys are one component in the factor used to establish the reliability indices and the slight reduction in the level of measured performance on which the Staff concludes that reliability expectations are not aligned, we are convinced that it is merely a slight difference between the Company's and customers' expectations.

We also recognize that customer satisfaction is dependent on whether the customer has recently experienced any service outages and how quickly service was restored.

The Commission finds that, adoption of the DIR and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and better align the Company's and its customers' expectations. The Company appears to be placing sufficient proactive emphasis on and will dedicate sufficient resources to the reliability of its distribution system. Having made such a finding, the Commission approves the DIR as an appropriate incentive to accelerate recovery of AEP-Ohio's prudently incurred distribution investment costs. We emphasize that the DIR mechanism shall not include any gridSMART costs; the gridSMART projects shall be separate and apart from the DIR mechanism and projects. With this clarification, we believe it is unnecessary to address the Company's request to allow the remaining net book value of removed meters to be included as a regulatory asset recoverable through the DIR mechanism.

We agree with Staff and Kroger that the DIR mechanism be revised to account for ADIT. The Commission finds that it is not appropriate to establish the DIR rate mechanism in a manner which provides the Company with the benefit of ratepayer supplied funds. Any benefit resulting from ADIT should be reflected in the DIR revenue requirement. Therefore, the Commission directs AEP-Ohio to adjust its DIR to reflect the ADIT offset.

As was noted in the December 14, 2012 *[SIC, should be 2011]* Order on the ESP 2, we find that granting the DIR mechanism requires Commission oversight. We believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs. AEP-Ohio is correct to aspire to move from a reactive to a more proactive replacement maintenance program. The Company is directed to work with Staff to develop a plan to emphasize proactive distribution maintenance that focuses spending on where it will have the greatest impact on maintaining and improving reliability for customers. Accordingly, AEP-Ohio shall work with Staff to develop the DIR plan and file the plan for Commission review in a separate docket by December 1, 2012.

With these modifications, we approve the DIR mechanism, and direct Staff to monitor, as part of the prudence review, by an independent auditor for in-service net capital additions and compliance with the proactive distribution maintenance plan developed with the assistance of the Staff. The proactive distribution infrastructure plan shall quantify reliability improvements expected, ensure no double recovery, and include a demonstration of DIR expenditures over projected expenditures and recent spending levels. The DIR mechanism will be reviewed annually for accounting accuracy, prudency and compliance with the DIR plan developed by the Staff and AEP-Ohio.

On Pages 61-63

14. GridSMART

The Company's modified ESP application proposes the continuation of the gridSMART rider approved by the Commission in the ESP 1 Order, with two modifications.... Further, AEP-Ohio states that the Company intends to deploy elements of the gridSMART program throughout the AEP-Ohio service territory as part of the proposed DIR program proposed in this proceeding. (AEP-Ohio Ex. 107 at 10; AEP-Ohio Ex. 110 at 9-13.)

OCC and APJN submit that, to the extent that the Company proposes to include gridSMART costs in the DIR, there are numerous concerns that need to be addressed before the Company is authorized to proceed. Staff, OCC, and APJN retort that the Company's proposed expansion of the gridSMART project, before any evaluation and analysis of the success of gridSMART Phase 1, is inconsistent with sound business principles and should be rejected by the Commission. Therefore, these parties recommend that the Company not proceed with Phase 2 until evaluation of Phase 1, is complete, on or about March 31,2014. (Staff Ex. 105 at 5-6; OCC/APJN Br. at 96-97.)

More specifically, Staff reasons that the costs of the expansion of various gridSMART technologies have not been determined, the benefits of the gridSMART expansion defined nor customer acceptance of such technologies evaluated. In addition, Staff claims that the Company has stated that certain components of the aging distribution infrastructure do not support gridSMART technologies. Despite Staffs position on the commencement of Phase 2 of the gridSMART project. Staff does not oppose the Company's installation, at the Company's expense and risk of recovery, of proven distribution technologies that can proceed independently of gridSMART, which address near term generation reliability concerns, such as integrated voltage variation control (IVVC), and do not present any security or interoperability issues or violate requirements set forth by the National Institute of Standards and Technology Interagency Report. Staff endorses the continuation of the gridSMART rider to be collected from all AEP-Ohio customers. Staff emphasizes that equipment should not be recoverable in the gridSMART rider until it is installed, has completed and passed thorough testing, and has been placed in-service. (Staff Ex. 105 at 3-6; Staff Ex. 107 at 3-13.)

AEP-Ohio points out that no intervener has expressed any opposition to the continuation and completion of gridSMART Phase 1 and, accordingly, AEP-Ohio requests approval of this aspect of the modified ESP. AEP-Ohio also requests that the Commission provide some policy guidance on whether the Company should proceed with the expansion of the gridSMART program.

As the Commission noted in AEP-Ohio's ESP 1 Order:

> [I]t is important that steps be taken by the electric utilities to explore and implement technologies... that will potentially provide long-term benefits to customers and the electric utility. GridSMART Phase 1 will provide CSP with beneficial information as to implementation, equipment preferences, customer expectations, and customer education requirements... More reliable service is clearly beneficial to CSPs customers. The Commission strongly supports the implementation of AMI [advanced metering infrastructure] and DA [distribution automation initiative], with HAN [home area network], as we believe these advanced technologies are the foundation for AEP-Ohio providing its customers the ability to better manage their energy usage and reduce their energy costs.

(ESP 1 Order at 34-35.)

The Commission is not wavering in its conviction as to the benefits of gridSMART. Thus, we direct AEP-Ohio to continue the gridSMART Phase 1 project and to complete the review and evaluation of the project. We are approving the Company's request to initiate Phase 2 of the gridSMART project, prior to the March 31, 2014, completion of the evaluation of gridSMART Phase 1, with those technologies that have to-date demonstrated success and are cost-effective... However, the Company shall include, as Staff recommends, IVVC only within the distribution investment rider, as IVVC is not exclusive to the gridSMART project. IVVC supports the overall electric system reliability and can be installed without the presence of grid smart technologies, although IVVC enhances or is necessary for grid smart technology to operate properly and efficiently. Furthermore, the gridSMART Phase 1 rider was approved with specific limitations as to the equipment for which recovery could be sought, and a dollar limitation.[188] Any gridSMART

[188] ESP 1 Order at 37-38; ESP 1 Entry on Rehearing at 18-24 (July 23,2009).

investment beyond the Phase 1 pilot, which is not subject to recovery through the DIR mechanism, should be recovered through a mechanism other than the current gridSMART rider, for example, through a gridSMART Phase 2 rider. The current gridSMART rider allows for recovery on an "as spent" basis, with audits directed toward truing-up expenditures with collections through the rider rate. Keeping subsequent non-DIR, gridSMART expenditures in a new separate recovery mechanism facilitates enforcement and a Commission determination that recovery of gridSMART investment occur only after the equipment is installed, tested, and is in-service. With these clarifications, the Commission approves the Company's request to continue, as a part of this modified ESP, the current gridSMART rider mechanism, subject to annual true-up and reconciliation based on the Company's prudently incurred costs, and to extend the rate to include OP as well as CSP customers.

We note that the gridSMART Phase 1 rider was last evaluated for prudency of expenditures, reconciled for over- and under-recoveries and the rate mechanism adjusted in Case No. 11-1353-EL-RDR, with the rate effective beginning September 1, 2011. Despite the Commission's February 23, 2012 rejection of the application in this ESP 2 proceeding, the recovery of the gridSMART rate mechanism continued consistent with the Entry issued March 7, 2012. Accordingly, the gridSMART rider rate mechanism approved in Case No. 11-1353-EL-RDR shall continue at the current rate until revised by the Commission. We also note that in Case No. 11-1353-EL-RDR, the Commission deducted an amount from the Company's claim for the loss on the disposal of electro-mechanical meters. The Commission notes, as we stated in the Order issued August 4, 2011, that we will address the meter issue in the Company's pending gridSMART rider application, Case No. 12-509-EL-RDR, and nothing in this Order on the modified ESP should be interpreted to the contrary.

On pages 64-65

16. Enhanced Service Reliability Rider

As part of AEP-Ohio's ESP 1 case, AEP-Ohio proposed an enhanced service reliability rider (ESRR) program which included four components, of which only the transition to a cycle-based vegetation management program was approved by the Commission. In this modified ESP, AEP-Ohio requests continuation of the ESRR and the Company's transition to a four-year, cycle-based trimming program. Further, the Company proposes the unification of the ESRR rates for each rate zone into a single rate, adjusted for anticipated cost increases over the term of the ESP, with carrying cost on capital assets and annual reconciliation. AEP-Ohio admits that before the initiation of the transitional vegetation management program, the number of tree-related circuit outages had gradually increased. However, the Company states that with the initiation of the new vegetation management program, the number of tree-caused outages has been reduced and service reliability has improved. AEP-Ohio proposes to complete the transition from a performance-based program to a four-year, cycle-based trimming program for all of the Company's distribution circuits as approved by the Commission in the prior ESP. However, the Company notes that the vegetation management plan was implemented as a five-year transition program and, as a result of the delay in adopting a second ESP and increases in the expected costs to complete implementation of the cycle-based trimming program, it is now necessary to extend the implementation period to include an additional year into 2014. AEP-Ohio requests incremental funding for 2014 for both the completion of the transition to a cycle-based vegetation management program of $16 million and an incremental increase of $18 million annually to maintain the cycle-based program. (AEP-Ohio Ex. 107 at 8; AEP-Ohio Ex. 110 at 5-9.)

Staff supports the continuance of the ESRR through 2014 but not any cost incurred thereafter. Staff reasons that after 2014, the Company's transition to a four-year, cycle-based vegetation management program will be complete and regular maintenance pursuant to the program will be part of the Company's normal operations, the cost of which should be recovered through base rates not through the ESRR. Further, Staff argues that the ESRR funding level for the period 2012 through 2014 is overstated due to the increased ESRR baseline reflected in the Company's recent distribution rate case.[189] According to Staff, to reach the rate base in the Stipulation in the distribution rate case, Staff agreed to an increase in the revenue requirement for CSP and OP which incorporated an annual increase in vegetation management operation and maintenance expense of $17.8 million annually for 2012 through 2014 over its recommendation in the Staff Report. For that reason, Staff asserts that vegetation management operation and maintenance expense must be reduced by $17.8 million annually for the period 2012 through 2014. Further, Staff recommends that the Commission direct AEP-Ohio to file, pursuant to Rule 4901:1-10-27(E)(2) and (3), O.A.C, by no later than December 31, 2013, a revised vegetation management program which commits the Company to complete end-to-end trimming on all of its distribution circuits every four years beginning January 1, 2014 and beyond. (Staff Ex. 106 at 11-14; Tr. at 4363-4365.)

AEP-Ohio retorts that Staff ignores the fact that the Stipulation, and the Commission Order approving the Stipulation, in the Company's distribution rate case do not detail any increase in the ESRR baseline. AEP-Ohio requests that the Commission reject Staff's view of the rate case settlement as unsupported and improper, after the issuance of a final, non-appealable order in the case. As to Staff's proposed termination of funding after 2014, the Company offers that such would undermine the benefits of the cycle-based trimming. (AEP-Ohio Reply Br. at 76-77.)

The Commission concludes that while the Stipulation in the distribution rate case reflects an increase in the baseline operations and maintenance expense from the level recommended in the Staff Report, there is no evidence in the Stipulation or the Commission's Order adopting the Stipulation which specifically supports a $17.8 million increase in operations and maintenance expense for the vegetation management program. Accordingly, the Commission approves the continuation of the vegetation management program, via the ESRR, and merger of the rates, as requested by the Company for the term of the modified ESP, through May 31, 2015. Within 90 days after the conclusion of the ESRR, the Company shall make the necessary filing for the final year review and reconciliation of the rider. We direct AEP-Ohio to file a revised vegetation management program consistent with this Order and Rule 4901:1-10-27(E)(2) and (3), O.A.C, by no later than December 31, 2012. We see no need to wait until December 2013 for the filing, as requested by Staff, in light of our ruling in this Order.

On page 68

19. Strom Damage Recovery Mechanism

AEP-Ohio proposes a storm damage recovery mechanism be created to recover any incremental expenses incurred due to major storm events (AEP-Ohio Ex. 110 at 20). AEP-Ohio provides that the mechanism would be created in the amount of $5 million per year in accordance with the settlement in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR. In support of the storm damage recovery mechanism, AEP-Ohio witness Kirkpatrick notes that absent the mechanism, forecasted operation and maintenance (O&M) funds would be constantly diverted to cover the expense of major storms, which could disrupt planned maintenance activities and impact system reliability. The determination of what a major storm is or is not would be determined by methodology outlined in the IEEE Guide for Electric Power Distribution Reliability Indices, as set forth in Rule 4901:1-10-10(B), O.A.C. (Id.) Any capital costs that would be incurred due to a major

[189] In re AEP-Ohio, Opinion and Order, Case No. 11-351-EL-AIR, et al. (December 14,2011).

storm would either become a component of the DIR or would be addressed in a distribution rate case {Id. at 21). Upon approval of the storm damage recovery mechanism AEP-Ohio will defer the incremental distribution expenses above or below the $5 million storm expense beginning with the effective date of January 1, 2012 (AEP-Ohio Ex. 107 at 10)....

...In establishing its storm damage recovery mechanism, AEP-Ohio failed to specify how recovery of the deferred asset would actually work or would occur. As proposed, it is unknown when AEP-Ohio would seek recovery, or whether anything over or under $ 5 million would become a deferred asset or liability. As it currently stands, the storm damage recovery mechanism is open-ended and should be modified.

Therefore, we find that AEP-Ohio may begin deferral of any incremental distribution expenses above or below $5 million, per year, subject to the following modifications. Further, throughout the term of the modified ESP, AEP-Ohio shall maintain a detailed accounting of all storm expenses within its storm deferral account, including detailed records of all incidental costs and capital costs. AEP-Ohio shall provide this information annually for Staff to audit to determine if additional proceedings are necessary to establish recovery levels or refunds as necessary.

In the event AEP-Ohio incurs costs due to one or more unexpected, large scale storms, AEP-Ohio shall open a new docket and file a separate application by December 31 each year throughout the term of the modified ESP, if necessary. In the event an application for additional storm damage recovery is filed, AEP-Ohio shall bear the burden of proof of demonstrating all the costs were prudently incurred and reasonable….

<u>Case No. 12-2627-EL-RDR Finding and Order dated November 28, 2012</u>

On page 2

(6) The Commission finds that AEP-Ohio's application to update the DIR, as corrected on November 16, 2012, is reasonable and should be approved. The proposed DIR rate does not appear to by unjust or unreasonable, and, therefore, we find that it is unnecessary to hold a hearing in this matter. According, the new DIR rate should be implemented beginning with bills rendered for the first billing cycle of December 2012. Notwithstanding the Commission's approval of AEP-Ohio's proposed tariffs to establish a new DIR rate for the first billing cycle of December 2012, we note that the DIR remains subject to an annual audit and reconciliation.

(7) With respect to AEP-Ohio's future quarterly DIR filings, the Commission clarifies that the proposed DIR rate shall be automatically approved 60 days after the application is filed, with the new rate to take effect on the proposed effective date, unless the 60-day period is suspended by the Commission. As noted above, however, the DIR is subject to adjustment during the annual audit and reconciliation.

<u>Case No. 11-346-EL-SSO Entry on Rehearing dated January 30, 2013</u>

On pages 44-49

XI. DISTRIBUTION INVESTMENT RIDER

(47) AEP-Ohio asserts that the Commission's failure to establish a final reconciliation and true-up for the distribution investment rider (DIR), which will expire with at the conclusion of the ESP, was unreasonable. AEP-Ohio reasons that it is unable to determine whether the DIR will have a zero balance upon expiration of the rider such that final reconciliation is necessary to address any over-recovery or under-recovery. AEP-Ohio adds that the Commission is clearly vested with the authority to direct reconciliation of the DIR, as was done for the ESRR and in other proceedings.

Accordingly, AEP-Ohio contends that it was unreasonable for the Commission to not provide for reconciliation and true-up for the DIR.

We grant AEP-Ohio's request for rehearing to facilitate a final reconciliation and true-up of the DIR at the end of the ESP. Accordingly, within 90 days after the expiration of this ESP, AEP-Ohio is directed to file the necessary information for the Commission to conduct a final review and reconciliation of the DIR.

(48) AEP-Ohio asserts that the Opinion and Order unreasonably adjusted the revenue requirement for accumulated deferred income taxes (ADIT). AEP-Ohio claims that the ADIT offset is inconsistent with the Commission approved stipulation filed in the Company's latest distribution rate case. Case No. 11-351-EL-AIR et al., (Distribution Rate Case) as the revenue credit did not take into account an ADIT offset which, as calculated by AEP-Ohio, results in the distribution rate case credit being overstated by $21.329 million. AEP-Ohio notes that the DIR was used to offset the rate base increase in the distribution rate case and included a credit for residential customers and a contribution to the Partnership with Ohio fund and the Neighbor-to-Neighbor program. AEP-Ohio argues that it is fundamentally unfair to retain the benefits of the distribution rate case settlement and subsequently impose the cost of ADIT offset through the DIR in the ESP when AEP-Ohio cannot take action to protect itself from the risk. On rehearing, AEP-Ohio asks that the Commission restore the balance struck in the distribution rate case settlement by eliminating the ADIT offset to the DIR.[190]

OCC/APJN reminds the Commission that AEP-Ohio's distribution rate case was resolved by Stipulation and the Stipulation does not include any provision for AEP-Ohio to adjust the revenue credit to customers contingent upon Commission approval of the DIR. OCC/APJN notes that the Distribution Rate Case Stipulation details the DIR revenues and the distribution of the revenue credit and also specifically provides AEP-Ohio the opportunity to withdraw from the Stipulation if the Commission materially modifies the DIR in this proceeding. Finally, OCC/APJN asserts that AEP-Ohio was the drafter of the Distribution Rate Case Stipulation and, pursuant to Ohio law, any ambiguities in the document must be construed against the drafting party.

The Commission has considered the appropriateness of incorporating the effects of ADIT on the calculation of a revenue requirement and carrying charges in several proceedings. In regard to determination of the revenue requirement for the DIR, we emphasize, as we stated in the Opinion and Order:

> The Commission finds that it is not appropriate to establish the DIR rate mechanism in a manner which provides the Company with the benefit of ratepayer supplied funds. Any benefits resulting from ADIT should be reflected in the DIR revenue requirement.

None of the arguments made by AEP-Ohio convinces the Commission that its decision in this instance is unreasonable or unlawful. As such, we deny AEP-Ohio's request for rehearing of this issue.

(49) Kroger contends that the Opinion and Order notes, but does not directly address or incorporate, Kroger's argument not to combine the DIR for the CSP and OP rate zones without offering any rationale. Kroger reiterates its claims that the DIR costs are unique and known for each rate zone and blending the DIR rates will ultimately require one rate zone to subsidize the costs of

[190] AEP-Ohio Ex. 151 at 9-10, Tr. at 2239.

service for the other. Kroger requests that the Commission grant rehearing and reverse its decision on this issue.

AEP-Ohio opposes Kroger's request to maintain separate DIR rates and accounts for each rate zone. AEP-Ohio argues that the Commission specifically noted and explained why certain rider rates were being maintained separately. Given that AEP-Ohio's merger application was approved, AEP-Ohio states that it is unreasonable for the Company to establish separate accounts for the DIR.

The Commission notes that the DIR is a new plan approved by the Commission in the ESP and the distribution investment plan will take into consideration the service needs of the AEP-Ohio as a whole. Kroger's request to establish separate and distinct DIR accounts and rates would result in maintaining and essentially continuing CSP and OP as separate entities. Kroger has not provided the Commission with sufficient justification to continue the distinction between the rate zones or demonstrated any unreasonable disadvantage or burden to either rate zone. The focus of the DIR will be on replacing infrastructure, irrespective of rate zone, that will have the greatest impact on improving reliability for customers. The Commission denies Kroger's request to reconsider adoption of the DIR on a rate zone basis.

(50) OCC/APJN argue on rehearing that the Commission failed to apply the appropriate statutory standard in Section 4928.143(B)(2)(h), Revised Code. As OCC/APJN interpret the statute, it requires the Commission to determine that utility and customer expectations are aligned.

AEP-Ohio retorts that OCC/APJN misinterpret that statute and ignore the factual record in the case to make the position which was already rejected by the Commission. AEP-Ohio reasons that in their attempt to attack the Opinion and Order, OCC/APJN parsed words and oversimplified the purpose of the statute.

The Opinion and Order discusses AEP-Ohio's reliability expectations and customer expectations as well as OCC/APJN's interpretation of the requirements of Section 4928.143(B)(2)(h), Revised Code.56 OCC/APJN claim that the statutory requirement is that customer and electric distribution utility expectations be aligned at the present time. We reject their claim that the Opinion and Order focused on a forward looking statutory standard and, therefore, did not apply the standard set forth in Section 4928.143(B)(2)(h), Revised Code. The Commission interprets Section 4928.143(B)(2)(h), Revised Code, to require the Commission to examine the utility's reliability and determine that customer expectations and electric distribution utility expectations are aligned to approve an energy delivery infrastructure modernization plan. The key for the Commission is not, as OCC/APJN assert, to find that customer and utility expectations were aligned, are currently aligned or will be aligned in the future but to maintain, to some degree, the reasonable alignment of customer and utility expectations continuously. As noted in the Opinion and Order, and in OCC/APJN's brief, over 70 percent of customers do not believe their electric service reliability expectations will increase and approximately 20 percent of customers expect their service reliability expectations to increase. AEP-Ohio emphasized aging utility infrastructure and the Commission expects that aging utility infrastructure increases outages and results in the eroding of service reliability. The Commission found it necessary to adopt the DIR to maintain utility reliability as well as to maintain the general alignment of customer and utility service expectations. Thus, the Commission rejects the arguments of OCC/APJN and denies the request for rehearing.

(51) OCC/APJN also assert that the DIR component of the Opinion and Order violates the requirements of Section 4903.09, Revised Code, because it did not address Staff's request for details on the DIR plan. In addition, OCC/APJN contend that the Opinion and Order failed to address details about the DIR plan as raised by Staff, including quantity of assets, cost for each asset class, incremental costs and expected improvement in reliability.

We disagree. The Opinion and Order specifically directed AEP-Ohio to work with Staff to develop the plan, to focus spending where it will have the greatest impact and quantify reliability improvements expected, to ensure no double recovery, and to include a demonstration of DIR expenditures over projected expenditures and recent spending levels. Therefore, we also deny this aspect of OCC/APJN's request for rehearing of the Opinion and Order. Finally, the Commission clarifies that the DIR quarterly updates shall be due, as proposed by Staff witness McCarter, on June 30, September 30, December 30 and May 18, with the final filing due May 31, 2015, and the DIR quarterly rate shall be effective, unless suspended by the Commission, 60 days after the DIR update is filed.

(52) OCC/APJN contend that in their initial brief they argued that adoption of the DIR would impact customer affordability without the benefit of a cost benefit analysis. With the adoption of the DIR, OCC/APJN reason that the Opinion and Order did not address customer affordability in light of the state policies set forth in Section 4928.02, Revised Code, and. therefore, the Opinion and Order violates Section 4903.09, Revised Code.

We reject the attempt by OCC/APJN to focus exclusively on the DIR as the component of the ESP that must support selective state policies. First, we note that the Ohio Supreme Court has ruled that the policies set forth in Section 4928.02, Revised Code, do not impose strict requirements on any given program but simply expresses state policy and function as guidelines for the Commission to weigh in evaluating utility proposals. Nonetheless, we note that the ESP mitigates customer rate increases in several respects. The provisions of which serve to mitigate customer rate increases include, but are not limited to, stabilizing base generation rates until the auction process is implemented, June 1, 2015; requiring that a greater percentage of AEP-Ohio's standard service offer load be procured through auction sooner than proposed in the application; continuance of the gridSMART project so that more customers will benefit from the use of various technologies to allow customers to better control their energy consumption and costs; and developing electronic system improvements to facilitate more retail competition in the AEP-Ohio service area. Thus, while the adoption of the DIR supports the state policy to ensure reliable and efficient retail electric service to consumers in AEP-Ohio service territory, the above noted provisions of the approved ESP serve not only to mitigate the bill impact for at-risk consumers but all AEP-Ohio consumers. On that basis, the Opinion and Order supports the state policies set forth in Section 4928.02, Revised Code. Thus, we reject OCC/APJN's attempt to narrowly focus on the DIR as the component of the ESP that must support the state policies and deny the request for rehearing.

Case No. 13-419-EL-RDR Opinion and Order dated April 23, 2014

On pages 3-5, Summary of Stipulation

III. Summary of Stipulation

As stated previously, an amended stipulation signed by AEP Ohio and Staff was filed on January 17, 2014. The stipulation was intended by the signatory parties to resolve all of the outstanding issues in this proceeding (Jt. Ex. 1 at 1). The stipulation includes, inter alia, the following provisions:

(1) Upon approval of the stipulation, AEP Ohio agrees to reduce the December 2012 DIR revenue requirement by $6,154.39 so that the rider recommended by the signatory parties for adoption is 11.93845 percent of base distribution rates, such that a corresponding adjustment will be made in the quarterly update that follows the decision adopting the stipulation. The adjustment reflects the removal of

commercial activity tax on equity from the pretax weighted average cost of capital component of the carrying charge rate, removal of the Commission and OCC assessment, and exclusion of land held for future use. This aggregate adjustment was agreed to as part of a compromise and settlement of all of the financial issues except for the AMI meters, which are addressed separately below.

(2) The signatory parties recommend that the additional 22,000 AMI meters, which were installed after completion of the gridSMART Phase 1 rider, should be recovered through the gridSMART Phase 2 rider going forward, to the extent that it is approved by the Commission and subject to the following implementation terms:

(b) AEP Ohio will make a filing in the pending gridSMART Phase 2 rider update case. Case No. 13-1939-EL-RDR, within 30 days of finalizing the stipulation, recommending recovery of the 22,000 AMI meter investment as part of the decision in that case.

(c) Upon a decision, in Case No. 13-1939-EL-RDR, approving the inclusion of the 22,000 AMI meters in the gridSMART Phase 2 rider, AEP Ohio will record a DIR adjustment to exclude the investment at the same time that it files its compliance tariffs to update the gridSMART Phase 2 rider. This adjustment will be included in AEP Ohio's next quarterly DIR adjustment filing.

(d) In reaching this agreement. Staff is not endorsing the prudency of the 22,000 AMI meter investment at this time and reserves the right to conduct a prudency review in the gridSMART Phase 2 docket. Case No. 13-1939-EL-RDR. In processing the filing in Case No. 13-1939-EL-RDR, Staff will determine whether any additional audit review of the 22,000 AMI meter investment is needed, given the audit review of this AMI investment already conducted by Blue Ridge, and will conduct its review accordingly. The signatory parties take no position at this time whether the prior investment in these 22,000 AMI meters should be included in the cost-benefit analysis associated with the gridSMART Phase 2 initiative. The AMI investment will be subject to a cost-benefit analysis and the signatory parties agree that one of the benefits to be credited is the savings associated with recovering this investment through the gridSMART Phase 2 rider as compared to the gridSMART Phase 1 rider.

(e) Upon the future filing of the additional reduction to the DIR related to moving recovery of the 22,000 AMI meter investment to the gridSMART Phase 2 rider, the DIR will be reduced by the net book value of the additional meters at that time. That adjustment will be reflected in the next quarterly filing. The signatory parties understand that the DIR is also subject to further adjustment based on future filings by AEP Ohio.

On page 7, Findings of Fact and Conclusions of Law

(6) At the hearing, a stipulation was submitted, intending to resolve all of the issues in this case. No party opposed the stipulation.

(7) The stipulation meets the criteria used by the Commission to evaluate stipulations, is reasonable, and should be adopted.

Case No. 13-2385-EL-SSO Opinion and Order dated February 25, 2015

On pages 40-47

6. Distribution Investment Rider

The DIR was previously approved by the Commission, in the ESP 2 Case, to facilitate the timely and efficient replacement of aging infrastructure to improve service reliability. ESP 2 Case, opinion and Order (Aug. 8, 2012) at 46-47. Presently, the DIR is updated quarterly using FERC forms and AEP Ohio's DIR rider rates are automatically approved 60 days after the application is filed, unless the Commission specifically orders otherwise. The Commission reviews the DIR annually for accounting accuracy, prudency, and compliance with the DIR plan developed by AEP Ohio with Staff input.

In this ESP application, under the authority of R.C. 4928.143(B)(2)(h), AEP Ohio requests the continuation of the DIR, with certain modifications and adjustments. AEP Ohio requests that the DIR rate caps be established at $155 million for 2015, $191 million for 2016, $219 million for 2017, and $102 million for January 1 through May 31, 2018, for a total of $667 million. For any year that AEP Ohio's investment results in revenues to be collected that exceed the cap, the excess would be recovered and be subject to the cap applicable in the subsequent period. The same would be true when AEP Ohio's investment results in revenues to be collected that fall below the cap for the period; the cap for the subsequent period would be increased by the amount available from the prior period. AEP Ohio proposes DIR capital projects that primarily fall into eight categories: asset improvement, customer service, forestry, general, other, planning capacity, reliability, and system restoration. AEP Ohio reasons that these types of capital investments are key components in its strategy for maintaining the distribution system and improving reliability. One of the capital investments that AEP Ohio plans to make, if this ESP is approved, is to replace its 800 megahertz radio system at a cost of approximately $23 million. The radio system is used to support field communication, dispatching, remote equipment interrogation, global positioning satellite communications, service restoration, and remote meter reading. (Co. Ex. 1 at 9-10; Co. Ex, 4 at 17-19; Co. Ex. 14 at 5-7.)

However, AEP Ohio requests that the DIR, as currently implemented, be modified in three respects.[191] First, AEP Ohio requests that the DIR mechanism be modified such that the balance of each category of plant incurs an applicable associated carrying charge. Second, AEP Ohio proposes that the DIR be expanded to include general plant. Third, AEP Ohio requests that a gross-up factor be added to riders, including the DIR, to account for the Company's obligation to fund a portion of the budgets of the Commission and OCC. (Co. Ex. 13 at 5-7; Co. Ex. 14 at 1-2.)

Market Strategies International (MSI) conducted telephone surveys for AEP Ohio in2012 to determine customer reliability expectations. MSI conducted two series of telephone surveys, interviewing a total of 400 residential customers and 400 small commercial customers. According to the survey results, 69.8 percent of residential customers and 75.8 percent of small commercial customers believe that their electric service reliability expectations will stay about the same over the next five years. Significantly fewer customers surveyed, 13.0 percent of residential customers and 14.8 percent of small commercial customers, thought that their service reliability expectations over the next five years would increase somewhat. Some of the customers surveyed thought that

[191] AEP Ohio also requests that gridSMART Phase 1 capital costs be transferred into the DIR and that issue is addressed in the gridSMART section of this Opinion and Order

their service reliability expectations would increase significantly over the next five years, 5.8 percent of residential customers and 3.0 percent of small commercial customers. On the other hand, the surveys revealed that relatively few customers believe that their service reliability expectations will decrease somewhat, 5.3 percent of residential customers and 2.8 percent of small commercial customers. (Co. Ex. 4 at 5-8, Ex. SJD-1 at 1-2.)

AEP Ohio submits that the DIR advances the state policies expressed in R.C. 4928.02(A), (D), (E), (G), and (M). Further, AEP Ohio encourages the Commission to find that the DIR, as proposed, satisfies the statutory requirements set forth in R.C. 4928.143(B)(2)(h) and to approve the rider. (Co. Br. at 84.)

OHA supports the Commission's approval of the DIR, as proposed by AEP Ohio (OHA Br. at 3). Similarly, Staff generally does not oppose the continuation of the DIR, as the Commission approved the mechanism and the process for review in AEP Ohio's previous ESP proceedings. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 46-47. Staff testified that AEP Ohio's most recent system reliability standards were developed pursuant to Ohio Adm. Code 4901:1-10-10(B)(2), in Case No. 12-1945-EL-ESS, and adopted by the Commission in accordance with a stipulation filed by all of the parties to the proceeding. In re Ohio Power Company, Case No. 12-1945-EL-ESS (Reliability Standards Case), Opinion and Order (Mar. 19, 2014) at 6. In the Reliability Standards Case, the Commission established a customer average interruption duration index (CAIDI) of 150.0 minutes and a system average interruption frequency index (SAIFI) of 1.20, excluding "major event days," as defined by the Institute of Electrical and Electronics Engineers. The new CAIDI and SAIFI standards were first applicable to AEP Ohio for calendar year 2013. Staff confirmed that, based on AEP Ohio's application filed in Case No. 14-517-EL-ESS, the Company met both its SAIFI and CAIDI performance standards for 2013. For that reason. Staff recommends that the Commission find that AEP Ohio's reliability expectations are aligned with those oi its customers. (Staff Ex. 10 at 5-6;Staff Ex. 17 at 2; Staff Br. at 43.)

Staff, however, opposes the substantial increase and modifications that AEP Ohio requests with respect to the DIR. Regarding the request to include general plant. Staff, OCC, and Kroger assert that the request is another example of AEP Ohio's attempt to avoid a distribution rate case. OCC argues that general plant is not, by definition, infrastructure and, therefore, it is not appropriate to include general plant in the DIR. Staff reasons that the recovery of general plant costs via a rider is inconsistent with the intent of the ESP statute and the Commission's directives with respect to the DIR. Noting the Commission's rationale for approving the DIR as stated in the ESP 2 Case, Staff asks the Commission to reaffirm its directive that AEP Ohio's DIR spending focus on those components that will best improve or maintain reliability. General plant, in Staff's and OCC's opinion, does not satisfy the Commission's stated criteria, because the types of general plant expenses that AEP Ohio seeks to include in the DIR do not directly relate to the reliability of the distribution system. Staff maintains that general plant like the radio system and service centers, at best, supports maintaining reliability, but does not directly relate to distribution system reliability. Staff argues that the DIR was never intended to facilitate the recovery of all capital expenditures. General plant. Staff reasons, does not satisfy the Commission's stated objective for the DIR, which is "to encourage the electric utility to proactively and efficiently replace and modernize infrastructure." ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 47. Staff requests that AEP Ohio's proposal to modify the DIR to include general plant be denied. (OCC Ex. 18 at 14; Staff Br. at 43-47; Staff Reply Br. at 34-36; OCC Br. at 85-86; OCC Reply Br. at 59-60; Kroger Reply Br. at 3-4.)

AEP Ohio responds that the general plant investments in question primarily consist of service centers and the radio communications systems that directly support the frontline employees. AEP Ohio witness Dias testified that some of the facilities were built in the World War II era and need work. AEP Ohio notes that the DIR plan will be discussed with Staff, as it has been since implementation, and filed with the Commission. AEP Ohio further notes that Staff witness McCarter indicated that, after a full review. Staff may agree to the inclusion of the radio system. (Tr. II at 344; Tr. IX at 2295; Co. Reply Br. at 73-74.)

AEP Ohio also proposes that the DIR be modified to include a factor to account for the Commission's and OCC's budgets. According to Staff, including a gross-up factor to account for AEP Ohio's share of the Commission's and OCC's budgets is short-sighted and unnecessary. Staff contends that there are only two scenarios where AEP Ohio would owe a significantly larger dollar amount for the assessments in a subsequent year; first, if AEP Ohio's revenues increase disproportionally to the revenues of all of the other regulated public utilities in Ohio; and, second, if there is an increase in either the Commission's or OCC's budget. Staff notes that the Commission's and OCC's budgets have not increased in recent years and are not expected to increase in the foreseeable future. Staff also argues that AEP Ohio did not demonstrate that its revenues would increase so disproportionately as to justify the proposed change in the gross-up factor. (Staff Ex. 17 at 4; Staff Br. at 47-48.)

OCC emphasizes AEP Ohio's failure to provide specific service reliability improvements for each DIR program implemented. OCC and OMAEG argue that AEP Ohio failed to present any analysis to support its claims that service reliability has and will deteriorate without the DIR. For that reason, OCC and OMAEG oppose any increase in the DIR without supporting documentation. (OMAEG Br. at 10; OCC Reply Br. at 56.)

If the Commission approves the continuation oi the DIR, Staff makes six recommendations to facilitate the Commission's efficient review of plant recovery costs across the Company's riders. More specifically. Staff recommends that, in all subsequent DIR filings, AEP Ohio include additional detailed account and subaccount information; employ jurisdictional allocations and accrual rates from the Distribution Rate Case; provide a full reconciliation between the functional ledger and FERC forms; detail the DIR revenue collected by month; and highlight and quantify any proposed changes to capitalization policy. Staff also recommends that the Commission direct AEP Ohio to file a fully updated depreciation study by November 2016, with a study date of December 31, 2015. (Staff Ex. 17 at 5-7.)

OCC notes that AEP Ohio's enhanced service reliability rider (ESRR) and DIR programs include the widening and clearing of right-of-ways. OCC recommends that the Commission delete $3.9 million from the forestry component of the DIR for each year 2015 through 2018 to avoid any double recovery by AEP Ohio. (Tr. II at 353; OCC Br. at 84-85.) Further, OCC contends that the depreciation reserve used to calculate property taxes should be adjusted to eliminate the cumulative amortization of the excess depreciation reserve and the net plant to which the property tax is applied (OCC Br. at 90). Staff concurs with OCC's recommendation (Staff Reply Br. at 36-37).

OCC believes that the DIR, as well as other riders, should not be allocated based on total base distribution revenues, as AEP Ohio proposes, but rather in proportion to the allocation of net electric plant in service as set forth in the cost-of-service studies filed in the Distribution Rate Case. OCC contends that AEP Ohio's allocation does not follow cost causation principles and would result in residential customers being charged approximately $29 million more than their fair share for the DIR, ESRR, and sustained and skilled workforce rider (SSWR). (OCC Ex. 14 at 5-12; OCC Br. at 107-109.) OEG and lEU-Ohio oppose OCC's reallocation proposal. OEG advocates that the costs underlying the DIR and the other riders are related to the provision of distribution service and it is, therefore, reasonable to allocate the rider costs to rate schedules on the basis of distribution revenues. OEG notes that the Commission adopted the DIR in the ESP 2 Case and reasons that it is appropriate for the Commission to follow this methodology for the new and modified riders proposed in these ESP proceedings. OEG also reasons that the approach recommended by OCC would require a fresh review of the cost of service and allocation methodology, which would equate to a "mini rate case" on rider allocation and rate design. OEG offers that such a review is outside of the scope and would unduly complicate the ESP proceedings. OEG and lEU-Ohio submit that the cost-of-service study relied on by OCC is outdated and reliance on the study would be unreasonable. OEG asserts that there is insufficient evidence in these proceedings to change an allocation method and rate design that the Conunission has previously vetted and determined to be fair, just, and reasonable. (OEG Br. at 27; lEU-Ohio Reply Br. at 28-30.)

OPAE and APJN challenge the DIR, noting that AEP Ohio is not claiming that reliability will decline if the DIR is not approved in this ESP. Given that the DIR currently constitutes approximately 17.1 percent of the average residential customer's distribution charges, OPAE and APJN reason that this rider makes electric service less affordable for residential customers who are struggling financially. On that basis, OPAE and APJN opine that it is reasonable for the Commission to discontinue the DIR. OPAE and APJN dispute AEP Ohio's contention that the DIR advances the state policy as expressed in R.C. 4928.02(A), which requires the availability to consumers of reliable and reasonably priced retail electric service. OPAE and APJN claim that AEP Ohio failed to present any testimony or discussion on brief indicating how the DIR complies with R.C. 4928.02(L), regarding the protection of at-risk populations. To address this oversight, OPAE and APJN suggest that the Commission require AEP Ohio to continue its annual $1 million funding commitment of the Neighbor-to-Neighbor program. Further, OPAE and APJN ask the Commission to direct AEP Ohio to contribute $1 million annually from shareholders to the Neighbor-to-Neighbor program. Finally, these intervenors ask the Commission to exempt income-eligible customers from riders approved in these ESP proceedings, including the DIR, to mitigate the impact of rate increases on at-risk customers, in support of R.C. 4928.02(L). (OPAE/APJN Reply Br. at 4-9.)

First, the Commission notes that, under R.C. 4928.143(B)(2)(h), an ESP may include provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. In determining whether to approve an ESP that includes a provision for distribution infrastructure modernization, R.C. 4928,143(B)(2)(h) directs the Commission to examine the reliability of the electric distribution utility's distribution system, ensure that the expectations of customers and the electric distribution utility are aligned, and determine that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

The Commission concludes that the record indicates that the vast majority of residential customers, 82.8 percent, and small commercial customers, 90.6 percent, believe their electric service expectations will be about the same, or increase somewhat over the next five years (Co. Ex. 4 at Ex. SJD-1 at 1-2). We note that, in the prior ESP proceedings, when the Commission approved the implementation oi the DIR, AEP Ohio's reliability measures were or had been below its reliability standards for 2010 and 2011. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 45. The record in these proceedings indicates that AEP Ohio has met its system reliability standards, CAIDI and SAIFI, for 2013 (Staff Ex. 10 at 5). Further, in the Reliability Standards Case, AEP Ohio agreed to file an updated reliability performance standards application by June 30, 2016, to reflect the impact of system design changes, technological advancements, geographical effects of programs like, but not limited to, the DIR and gridSMART programs, and the results of updated and current customer perception surveys. Reliability Standards Case, Opinion and Order (Mar. 19,2014) at 3.

As several of the parties have noted, the Commission approved the current DIR mechanism on the premise offered by AEP Ohio that aging infrastructure was the primary cause of customer outages and reliability issues and the DIR would improve reliability and support the installation of gridSMART technologies. The expanded DIR for which AEP Ohio seeks approval in these ESP proceedings far exceeds the justification offered and accepted by the Commission in approving the original DIR. Furthermore, it appears that AEP Ohio's interpretation of distribution infrastructure exceeds the intent of the statute (Tr. II at 436-438). Accordingly, we must deny AEP Ohio's request to significantly increase the amount to be recovered via the DIR and to incorporate general plant into the DIR mechanism. The record does not support such a significant expansion of the DIR. We find that AEP Ohio's DIR investments, at the level requested in these proceedings, would be better considered and reviewed in the context of a distribution rate case where the costs can be evaluated in the context of the Company's total distribution revenues and expenses, and the Company's opportunity to recover a return on and of its investment can be balanced against customers' right to reasonably priced service. (Staff Ex. 17 at 3.) For these reasons, the Commission denies AEP Ohio's request to increase the DIR to the level proposed in the ESP application and its request to incorporate general plant into the DIR mechanism.

Likewise, we deny AEP Ohio's request to adjust the DIR to account for the budgets of the Commission and OCC. The Commission agrees with the arguments of Staff that it is unlikely that the budgets of either agency will increase significantly over the next few years sufficient to justify revising the DIR (Staff Ex. 17 at 4). For this reason, we find that the requested modification to the DIR is inappropriate and unreasonable. Further, the Commission declines to adopt OCC's recommendation regarding the allocation of the DIR, as it is reasonable and consistent with the ESP 2 Case to allocate the rider costs to rate schedules on the basis of distribution revenues. We also decline to adopt OCC's proposal to adjust the forestry component of the DIR, because OCC has not established the occurrence of any double recovery through the DIR and ESRR. We note, however, that the DIR will continue to be subject to an annual audit.

The Commission finds merit in OCC's recommendation to revise the property tax calculation and, therefore, we adopt the adjustment recommended by OCC witness Effron (OCC Ex. 18 at 9-11; Staff Ex. 17 at 4-5). We further modify the DIR to adopt the six recommendations by Staff regarding detailed account information, jurisdictional allocations and accrual rates, reconciliation between functional ledgers and FERC form filings, revenue collected by month in the DIR, highlighting and quantifying DIR capitalization policy, and the filing of an updated depreciation study by November 2016, as outlined in Staff witness McCarter's testimony (Staff Ex. 17 at 5-7). However, the Commission recognizes that AEP Ohio is now performing at or above its established reliability standards and its reliability expectations appear to be aligned with its customers (Staff Ex. 10 at 5; Co. Ex. 4 at Ex. SJD-1 at 1-2). Therefore, we conclude that it is no longer necessary for AEP Ohio to work with Staff to develop a DIR plan, so long as the Company continues to perform at or above its adopted reliability standards.

To facilitate AEP Ohio's continued proactive investment in its aging distribution infrastructure, we approve the Company's request to continue the DIR at $124 million for 2015, $146.2 million for 2016, $170 million for 2017, and $103 million for January through May 2018, for a total of $543.2 million. The Commission has determined the annual DIR amounts based on the level of growth of three to four percent as permitted for the DIR in the ESP 2 Case. We find this to be a reasonable level to allow AEP Ohio to continue to replace aging distribution infrastructure in order to maintain and improve service reliability over the term of this ESP. With the modifications discussed herein, the Commission approves the continuation of the DIR as a component of the ESP.

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8. gridSMART Rider

In this ESP, AEP Ohio proposes the continuation of the gridSMART program, including the gridSMART rider initially approved by the Commission in the ESP 1 Case and continued in the ESP 2 Case. ESP 1 Case, Opinion and Order (Mar. 18, 2009) at 37-38, Entry on Rehearing (July 23, 2009) at 18-24; ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 62. However, AEP Ohio proposes modification of the gridSMART rider to transfer the remaining gridSMART Phase 1 costs to the DIR and use the gridSMART rider to track gridSMART Phase 2 costs. AEP Ohio reasons that gridSMART Phase 1 spending concluded at the end of 2013 and the gridSMART Phase 1 assets are not currently in base rates and have been excluded from the DIR. AEP Ohio requests that the DIR be modified to include the existing gridSMART Phase 1 assets. In support of the request, AEP Ohio claims that, beginning in June 2015, the total cost data for gridSMART Phase 1 will be available for reconciliation. With the reconciliation of gridSMART Phase 1, AEP Ohio posits that eliminating the removal of gridSMART Phase 1 net book value from the DIR mechanism will allow the Company to recover its investment on and of gridSMART Phase 1 assets in service. As of the filing of AEP Ohio's direct testimony in these cases, the Company expected to complete the installation of equipment associated with gridSMART Phase 1 and to submit data on gridSMART Phase 1 to the United States Department of Energy (USDOE) by December 31, 2014. AEP Ohio notes that it filed an evaluation of gridSMART Phase 1 with the Commission on or about March 31, 2014. AEP Ohio also notes that the Commission granted the Company authority to initiate the installation of certain gridSMART technologies that have demonstrated success and are cost-effective. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 62-63. AEP Ohio tiled its proposed expansion of the gridSMART program, gridSMART Phase 2, in Case No. 13-1939-EL-RDR (gridSMART 2 Case), on September 13, 2013. According to AEP Ohio's application in the gridSMART 2 Case, the Company plans to invest $465 million in gridSMART Phase 2. (Co. Ex. 1 at 10; Co. Ex. 3 at 4-5; Co. Ex. 4 at 10-11,13,15-16,20; Co. Ex. 13 at 7.)

AEP Ohio reasons that continuation of the gridSMART Phase 2 rider provides for continued deployment of emerging distribution system technologies where they can cost effectively improve the efficiency and reliability of the distribution system, develop performance standards and targets for service quality for all consumers, and encourage the use of energy efficiency programs and alternative energy resources. AEP Ohio submits that authority for including the gridSMART program in the ESP is set forth in R.C, 4928.143(B)(2)(h). AEP Ohio avers that the continuation of the proposed gridSMART Phase 2 program and rider is consistent with the policies listed in R.C. 4905.31(E) and R.C. 4928.02. (Co. Br. at 87-88.)

OCC argues that customers should not incur gridSMART Phase 2 charges on their bills until there has been a complete review of the gridSMART Phase 1 program and customer representatives and other interested stakeholders are provided an opportunity to raise any issues or concerns. On that basis, OCC requests that AEP Ohio's proposed treatment of gridSMART Phase 1 and gridSMART Phase 2 be rejected. (OCC Br. at 112-113.)

IGS, OEC, and EDF support AEP Ohio's gridSMART rider and the deployment of smart meters throughout the service territory. IGS, OEC, and EDF reason that smart meters are essential for the widespread offering of TOU products to customers. OEC and EDF believe that there is great potential for improved air quality resulting from the deployment of gridSMART technology, due to the reduced number of trucks that must be deployed to read meters and to disconnect and reconnect electric utility service. OEC and EDF also submit that Volt-VAR optimization will facilitate savings through energy efficiency and demand response programs. (OEC/EDF Br. at 7; IGS Reply Br. at 14.)

Further, while OEC and EDF recognize that the details of gridSMART Phase 2 will be determined in the gridSMART 2 Case, OEC and EDF aver that certain issues relating to the prudency of gridSMART costs and the associated benefits should be addressed by the Commission as a part of these ESP proceedings. To that end, OEC and EDF recommend that the Commission approve the continuation of the gridSMART program and the introduction of the gridSMART Phase 2 rider subject to nine conditions. (OEC/EDF Ex. 1 at 3-8; Tr. XII at 2784-2785.) OEC and EDF assert that their recommendations are intended to facilitate AEP Ohio's demonstration of the additional benefits of its gridSMART deployment, ease compliance with forthcoming United States Environmental Protection Agency regulations regarding greenhouse gas emissions for existing coal plants under Section 111(d) of the Clean Air Act, and ensure transparency and accountability (OEC/EDF Br, at 7-9; OEC/EDF Reply Br. at 7-S).

Kroger opposes AEP Ohio's request to transfer the remaining gridSMART Phase 1 cost into the DIR. Kroger notes that the Commission previously directed that gridSMART costs be recovered via a separate rider and not be incorporated into the DIR. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 63. Kroger submits that, if gridSMART costs are recovered outside the framework of a distribution rate case, the associated costs should be recovered through a separate rider that properly recovers costs on a per-customer basis. (Kroger Ex. 1 at 11; Kroger Br. at 4, 6.) In reply to Kroger, AEP Ohio states that moving gridSMART Phase 1 costs into the DIR is appropriate in order to dedicate the gridSMART Phase 2 rider to recovery of costs associated with Phase 2 of the program as approved in the gridSMART 2 Case. AEP Ohio also posits that the recommendations of OEC and EDF for gridSMART Phase 2 should be addressed in the gridSMART 2 Case, not these ESP proceedings. (Co. Reply Br. at 77-78.)

As discussed in the ESP 1 Case and the ESP 2 Case, the Commission continues to find significant long-term value and benefit for AEP Ohio and its customers with the implementation of advanced metering infrastructure, distribution automation, and other smart grid technologies. In the ESP 2 Case, the Commission approved AEP Ohio's request to initiate gridSMART Phase 2, directed that the Company file its proposed gridSMART Phase 2 project with the Commission, and directed that gridSMART Phase 2 costs be recovered through a separate rider as opposed to merging the costs into the gridSMART Phase 1 rider. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 62-63. For that reason, the Commission finds AEP Ohio's request to continue the gridSMART rider, with certain modifications as proposed by the Company, to be reasonable. Further, consistent with our decision in these proceedings to continue the gridSMART Phase 2 rider, we approve AEP Ohio's request to transfer gridSMART Phase 1 capital costs to the DIR mechanism upon the Company's accounting for all USDOE reimbursements due. (Co. Ex. 1 at 10; Co. Ex. 3 at 4-5; Co. Ex. 4 at 10-11, 13, 15-16, 20; Co. Ex. 13 at 7.) Given that, at the conclusion of gridSMART Phase 1, AEP Ohio will have recovered the vast majority of O&M expense, with only capital asset cost remaining to be collected over the useful life of installed gridSMART assets, it is efficient for the associated gridSMART Phase 1 costs to be included in the DIR. We remind AEP Ohio that, consistent with the Commission's directive in the ESP 2 Case, within 90 days after the expiration of ESP 2, the Company shall file an application for review and reconciliation of the gridSMART Phase 1 rider. ESP 2 Case, Entry on Rehearing (Jan. 30, 2013) at 53. After the Commission has reviewed and reconciled gridSMART Phase 1 costs, AEP Ohio may transfer the approved capital cost balance into the DIR, which will not be subject to the DIR caps, and may also transfer any unrecovered O&M balance into the gridSMART Phase 2 rider.

As with gridSMART Phase 1, the Commission will continue to annually review and approve AEP Ohio's gridSMART Phase 2 program, including the prudency of expenditures and the reconciliation of investments placed in service with revenues collected. We will also evaluate AEP Ohio's gridSMART Phase 2 program and determine the gridSMART rate to be charged customers, as well as consider OEC's and EDF's remaining recommendations, in the gridSMART 2 Case currently pending before the Commission.

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IV. DISTRIBUTION INVESTMENT RIDER

(34) In these proceedings, the Commission approved AEP Ohio's request to continue the distribution investment rider (DIR), with certain modifications. As approved in the ESP 3 Order, the modified DIR cap levels are $124 million for 2015, $146.2 million for 2016, $170 million for 2017, and $103 for January through May 2018. The Commission further modified the DIR to permit the balance oi each category ol plant to incur an applicable associated carrying charge, as proposed by AEP Ohio; revised the property tax calculation, as proposed by OCC; and to incorporate the six recommendations proposed by Staff regarding the submission of detailed account information, jurisdictional allocations and accrual rates, reconciliation between functional ledgers and FERC form filings, to require the submission of DIR revenue collected by month, direct that the Company notify, highlight, and quantify any proposed DIR capitalization policy amendments, and to require the filing of an updated depreciation study by November 2016. ESP 3 Order at 46-47.

(35) In its application for rehearing, AEP Ohio requests that, to the extent that the Commission does not issue a full rehearing decision within the 30-day timeframe set forth in R.C. 4903.10, the Commission issue an expedited rehearing decision on the DIR, due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio. AEP Ohio states that a prompt decision regarding the DIR annual revenue caps would enable the Company to continue to make improvements to its distribution infrastructure without significant disruption in the field in the short term, while also avoiding impairment of the Company's capabilities to continue to make improvements in an efficient manner over the long term.

(36) OMAEG argues that AEP Ohio's request for an expedited rehearing decision on the DIR issues is unreasonable and should be denied. OMAEG submits that the confusion that may result from an ad hoc approach to the rehearing process outweighs the alleged urgency for Commission action regarding the DIR. OCC also contends that the Commission should not address the DIR issues on rehearing on an expedited basis apart from the other issues raised by the parties. Noting that the Commission lacks statutory authority in this respect, OCC asserts that, if AEP Ohio's request is approved, the Commission will establish a dangerous precedent in which certain issues receive special treatment over others. Additionally, OCC asserts that it is always AEP Ohio's obligation to spend whatever capital is necessary to provide appropriate service reliability. OCC further asserts that the existence of the DIR does not preclude AEP Ohio from seeking recovery of distribution related investments through a distribution rate case, which would afford the Commission the opportunity to ensure that customers have actually received the service reliability improvements and efficiencies claimed by the Company.

(37) The Commission finds AEP Ohio's request for an expedited decision, while not prohibited under the rehearing process set forth in R.C. 4903.10, to be moot.

(38) In its application for rehearing, AEP Ohio contends that the Commission's modifications to the Company's DIR proposal are unreasonable and should be changed or clarified on rehearing. AEP Ohio, therefore, requests that the Commission adopt one or more of a number of options to better align the Company's and customers' reliability expectations and interests, consistent with R.C. 4928.143(B)(2)(h). First, AEP Ohio asserts that the Commission should reconsider its decision to reduce the Company-proposed DIR annual revenue caps and its denial of the Company's proposal to include general plant within the DIR. AEP Ohio points out that neither intervenors nor Staff recommended specific reductions to the annual revenue caps and, consequently, there is no evidence in the record regarding the resulting impacts from the reductions adopted by the Commission in the ESP 3 Order. AEP Ohio requests that the Commission reinstate the Company's proposed annual revenue caps or, alternatively, grant rehearing and receive further testimony to better gauge and understand the actual impacts of various levels of DIR revenue cap reductions on the Company's incremental reliability infrastructure investments. In support of its request, AEP Ohio notes that a static revenue cap as between 2014 and 2015, at the level of $124 million, will

have significant implications for capital reliability spend, while it will be logistically difficult and harmful to customers if the Company must abruptly pull back on pending capital projects that are already in progress. AEP Ohio explains that, due to the timing of the Commission's issuance of the ESP 3 Order, the Company was required to estimate the DIR revenue cap for 2015, establish its capital budget, and make contractual commitments to implement projects, and did so with the presumption that some additional revenue growth would be provided in 2015. With respect to AEP Ohio's proposal to include general plant in the DIR, the Company requests that the Commission grant rehearing and approve the expansion of the DIR to include infrastructure characterized by the Company as targeted general plant, most of which relates to the Company's service centers and radio communications system.

(39) In its memorandum contra, OMAEG responds that the Commission's decision not to include general plant in the DIR was reasonable, because, as noted by the Commission, the types of general plant expenses that AEP Ohio seeks to include in the DIR do not directly relate to the reliability of the distribution system. OMAEG also argues that the Commission should not adopt AEP Ohio's proposed annual revenue caps for the DIR on rehearing, given that the Company failed to present any analysis to support its claims that service reliability will deteriorate without the DIR, while the Company's proposed caps are excessive as compared with those currently in place, are unsupported by the evidence, and, in significant part, do not directly relate to distribution service reliability.

(40) OCC, in its memorandum contra, asserts that the Commission correctly rejected the inclusion of general plant in the DIR as beyond the intent of the statute. OCC notes that AEP Ohio had ample opportunity to present evidence in support of its claim that general plant has a direct impact on customer service and reliability, but nevertheless failed to meet its burden of proof on this issue.

(41) Alternatively, AEP Ohio requests that the Commission correct what the Company believes are mistaken DIR annual revenue caps. AEP Ohio points out that, in the ESP 3 Order, the Commission stated its intention to establish the annual revenue caps based on the level of growth of three to four percent as permitted for the DIR in the ESP 2 Case. AEP Ohio notes that the annual revenue caps approved by the Commission result in a zero percent growth in distribution revenue for 2015, followed by a more reasonable 2.9 percent growth in 2016 and 3 percent growth in 2017. According to AEP Ohio, if left unchanged, this situation will require the Company to pull back on capital investment in Ohio, which not only involves a reduced investment and potential reliability impacts but also could mean loss of contractor jobs currently sustained by the DIR funding. AEP Ohio states that, if the Commission elects to adopt DIR annual revenue caps at the lower end of its stated intention, meaning 3 percent, the annual caps would be $147 million in 2015, $171 million in 2016, $195 million in 2017, and $92 million for the first five months in 2018.

(42) OCC replies that AEP Ohio offers no evidence or documentation that indicates that the Commission erred in setting the DIR annual revenue caps. OCC maintains that the Commission's decision is consistent with the ESP 2 Case, while there is nothing in the ESP 3 Order to support AEP Ohio's assumption that the Commission intended to increase the DIR revenue cap from 2014 to 2015 by two to three percent. OCC argues that AEP Ohio's contention that there should be two to three percent growth from 2014 to 2015 requires the DIR program to be viewed as a single continuous six-year program instead of two distinct three year programs that were proposed, considered, and approved in two separate ESP proceedings.

(43) Next, AEP Ohio asserts that another option to partially offset the adverse effects of the annual revenue cap reductions would be for the Commission to clarify its intention in the ESP 2 Case regarding the annual revenue cap for 2012. AEP Ohio maintains that it is not clear whether the

Commission intended to prorate the $86 million revenue cap for 2012, based on an effective date of August 2012, such that the actual revenue cap for 2012 could either be $86 million as stated in the ESP 2 Case or $35.8 million (5/12 of $86 million). AEP Ohio notes that, as a result, the cumulative underspend that carries over to 2015 and beyond could be either $77.1 million or $26.9 million. AEP Ohio concludes that, if the Commission clarifies on rehearing that its intention in the ESP 2 Case was to adopt an $86 million revenue cap for 2012 without proration, it will produce a significant carryover amount that would help to alleviate the current problem for 2015 and beyond.

(44) lEU-Ohio responds, in its memorandum contra, that the Commission should reject AEP Ohio's request for clarification. IEU-Ohio notes that, because AEP Ohio failed to seek rehearing in the ESP 2 Case concerning the calculation of the annual revenue caps, the Company waived review of that provision of the Commission's decision in the ESP 2 Case. lEU-Ohio further notes that AEP Ohio did not seek rehearing of the revenue calculations that the Commission reviewed during the audit of the DIR for 2012 in Case No. 13-419-EL-RDR, which confirmed that a revenue cap of $86 million for 2012 was used to determine the carryover amount and, thus, there is no reasonable basis for the Commission to allow the Company to further increase its cap for 2015. IEU-Ohio concludes that AEP Ohio's request for clarification constitutes an untimely request for rehearing of the ESP 2 Case, is barred by the doctrines of res judicata and collateral estoppel, and, if granted, would result in unlawful retroactive ratemaking.

(45) OCC also argues that AEP Ohio's request for clarification regarding the DIR revenue cap for 2012 constitutes an unlawful attempt by the Company to relitigate aspects of the ESP 2 Case that are not at issue in the present proceedings. OCC requests that the Commission reject AEP Ohio's untimely effort to seek rehearing of the ESP 2 Case. OCC adds that there is nothing in the record or in the ESP 3 Order to support AEP Ohio's request that the cumulative underspend from the ESP 2 Case be permitted to carry over to 2015 and beyond.

(46) In their memorandum contra, OPAE/APJN contend that AEP Ohio's request for clarification regarding the DIR cap for 2012 should be considered an unlawful request for retroactive ratemaking. OPAB/APJN also point out that the level of DIR funding authorized by the Commission for the ESP 3 term is in addition to any carryover amounts. OPAE/APJN believe that the fact that AEP Ohio's DIR spending was below the DIR annual revenue caps established in the ESP 2 Case explains the level of the caps approved by the Commission for the ESP 3 term. Finally, OPAE/APJN assert that distribution service charges should be considered in the context of a distribution rate case and that the Commission appropriately encouraged AEP Ohio to seek base rate recovery of its distribution investments.

(47) In its application for rehearing, OMAEG argues that the Commission erred in allowing AEP Ohio to recover $543.2 million through the DIR over the course of the ESP, as recovery of distribution investments of that order of magnitude is not supported by record evidence and recovery of such costs is more appropriately addressed in the context of a base distribution rate case. Specifically, OMAEG maintains that nothing in the record indicates that the caps approved by the Commission represent a necessary level of recovery under the DIR for AEP Ohio to be able to continue to provide customers with reliable service. OMAEG, therefore, requests that the Commission revisit the caps established in the ESP 3 Order. OMAEG also requests that the Commission reverse its decision to relieve AEP Ohio of its responsibility to work with Staff to develop a DIR plan throughout the ESP term, particularly given that the Company did not file testimony or other documentation demonstrating any service reliability improvements related to specific distribution investments, in connection with the proposed ESP.

(48) In response, AEP Ohio points out that OMAEG's arguments are related to the statutory basis of riders and standards pertaining to the DIR result that are not found in statute. AEP Ohio

contends that, contrary to OMAEG's claim, there is no requirement that the Company demonstrate the benefit of each yearly DIR. AEP Ohio further contends that OMAEG's concerns regarding the reporting and quantification of reliability improvements have been resolved by the Commission in prior cases. With respect to OMAEG's request that AEP Ohio be required to continue to develop a DIR work plan with the assistance of Staff each year, the Company states that, while a formal requirement is no longer necessary, the Company intends to continue to obtain Staff's input and understand Staff's expectations when finalizing the DIR plan.

(49) OPAE/APJN assert that the Commission acted unreasonably and unlawfully when it approved the continuation of the DIR and maintained the rider's current cost allocation. OPAE/APJN claim that AEP Ohio's request to continue the DIR should have been rejected, because the Company did not consider the affordability of the DIR and did not demonstrate any quantifiable reliability benefits from the rider. OPAE/APJN contend that distribution related charges should be considered in distribution rate case proceedings and that riders should be limited to recovery of costs that are large, volatile, and outside of the utility's control, which, according to OPAE/APJN, AEP Ohio has not shown is the case for the DIR.

(50) AEP Ohio replies that the Commission has the authority to approve recovery of distribution related costs through riders and has often done so through ESP proceedings pursuant to R.C 4928.143(B)(2)(h). AEP Ohio believes that the time for a policy debate on whether riders should be included in an ESP filing has passed. Regarding the affordability of the DIR, AEP Ohio responds that its testimony reflects that, considering the impact of the entire ESP proposal, residential customers with typical usage are expected to see a monthly rate decrease beginning in June 2015.

(51) In the ESP 3 Order, the Commission denied AEP Ohio's request to increase the amount to be recovered via the DIR, at the level proposed in the Company's application, as well as the Company's request to include general plant in the DIR. The Commission found that the evidence of record does not support an expansion of the DIR to the extent proposed by AEP Ohio and that the Company's distribution investments, at the level requested in these proceedings, would be better considered and reviewed in the context of a distribution rate case. ESP 3 Order at 46. The Commission further found that, because AEP Ohio is performing at or above its established reliability standards and its reliability expectations appear to be aligned with its customers, it is no longer necessary for the Company to work with Staff to develop a DIR plan, as long as the Company continues to perform at or above its reliability standards. ESP 3 Order at 47. Finally, in order to facilitate AEP Ohio's continued proactive investment in its aging distribution infrastructure, the Commission approved the Company's request to continue the DIR at $124 million for 2015, $146.2 million for 2016, $170 million for 2017, and $103 million for January through May 2018. The Commission stated that the annual DIR revenue caps are based on a level of growth of three to four percent, consistent with the ESP 2 Case, and are intended to enable AEP Ohio to continue to replace aging distribution infrastructure as a means to maintain and improve service reliability over the course of the ESP. ESP 3 Order at 47. Upon review of AEP Ohio's grounds for rehearing with respect to the DIR, the Commission finds that the DIR annual revenue caps should be modified, as it was not the Commission's intent to provide for no growth in the annual cap from 2014 to 2015. We, therefore, find that the DIR annual revenue caps should be set at $145 million for 2015 (including amounts previously authorized in the ESP 2 Case), $165 million for 2016, $185 million for 2017, and $86 million for January through May 2018. We find that the adjusted caps shall reflect annual growth in the DIR, as a percentage of customer base distribution charges, of three to four percent, which was our objective in modifying the DIR annual revenue caps proposed by AEP Ohio for the ESP 3 term so that they more closely track the progression from the ESP 2 Case. Accordingly, the Commission grants rehearing with respect to AEP Ohio's request that the DIR annual revenue caps

established in the ESP 3 Order be adjusted, in order to enable the Company to continue to implement the DIR plan that is already underway for 2015. We find no merit in AEP Ohio's remaining grounds for rehearing regarding the DIR, which should, thus, be denied.

(52) Further, the Commission finds no merit in the alleged grounds for rehearing raised by OMAEG and OPAE/APJN with respect to the DIR. We find that the arguments raised by OMAEG and OPAE/APJN have already been thoroughly considered and rejected. ESP 3 Order at 43-45, 95. Regarding OMAEG's request that AEP Ohio be required to continue to work with Staff to develop an annual DIR work plan, we affirm our finding that it is no longer necessary to impose such a requirement, given the Commission's finding that the Company's reliability expectations appear to be aligned with its customers, as well as the fact that the Company has been meeting or exceeding its reliability standards. ESP 3 Order at 47. Additionally, as AEP Ohio acknowledges, the Company intends to continue to coordinate with Staff in the process of finalizing each annual DIR plan, which the Commission believes is a reasonable approach that should be implemented throughout the ESP term. For these reasons, OMAEG's and OPAE/APJN's applications for rehearing regarding the DIR should be denied.

V. ENHANCED SERVICE RELIABILITY RIDER

(53) OPAE/APJN submit that the ESP 3 Order is unreasonable to the extent that it approved the enhanced service reliability rider (ESRR) and DIR cost recovery allocation, outside the context of a distribution rate case and contrary to sound ratemaking practices. Further, OPAE/ APJN argue the riders do not incentivize the utility to control costs and should be limited to instances where the costs are large, volatile, and outside of the utility's control. AEP Ohio did not, according to OPAE/APJN, demonstrate that the ESRR or the DIR meet these criteria or that the financial integrity of the Company would be compromised if such costs were considered in the context of a distribution rate case. Further, OPAE /APJN argue ESRR and DIR costs to be recovered should be allocated to the customer classes consistent with cost causation principles and AEP Ohio's most recent cost of service studies as opposed to contribution to distribution revenues.

(54) AEP Ohio replies that this issue was raised by the intervenors and rejected by the Commission in the ESP 3 Order. Further, AEP Ohio notes the Commission resolved the recovery of incremental distribution investments in these cases in precisely the same manner as in other recent cases where the issue was considered. In re Ohio Edison Co., The Cleveland Elec. Illuminating Co., and The Toledo Edison Co., Case No. 12-1230-EL-SSO, Opinion and Order (July 18, 2012) at 56. AEP Ohio submits that the Commission has the authority to approve recovery of distribution related costs through riders in ESP proceedings pursuant to R.C. 4928.143(B)(2)(h). Accordingly, AEP Ohio requests that OPAE/APJN's request for rehearing be denied.

(55) The Commission finds that OPAE/APJN's arguments on the continuation of the distribution riders and the cost allocation method for the DIR and ESRR were raised, thoroughly considered, and rejected in the ESP 3 Order. ESP 3 Order at 49, 95. Intervenors assert no new arguments that persuade the Commission that the riders and the cost recovery allocation method should be revised on rehearing. The DIR and ESRR relate to the provision of distribution service and it is reasonable to allocate the cost of such riders on the basis of distribution revenues. In this ESP, the Commission continues the cost recovery allocation method previously adopted by the Commission in AEP Ohio's prior ESP proceedings. ESP 2 Case, Opinion and Order (Aug. 8, 2012) at 43-44, 77. Therefore, OPAE/APJN's request for rehearing should be denied.

Appendix B: Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report.

ADIT	Accumulated deferred income tax
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Meter Infrastructure
ARRA	American Reinvestment Recovery Act
APJN	Appalachian Peace and Justice Network
CAT	Commercial Activity Tax
CSP	Columbus Southern Power Company
DA	Distribution Automation
DIR	Distribution Investment Rider
DOE	Department of Energy
ESP	Electric Security Plan
ESSR	Enhanced Service Reliability Rider
FERC	Federal Energy Regulatory Commission
HAN	Home Area Network
IVVC	Integrated Volt-VAR Control
LOSA	Level of Signatory Authority
MRO	Market Rate Offer
OCC	Ohio Consumers' Counsel
OPCo	Ohio Power Company
PUCO	Public Utility Commission of Ohio
RFP	Request For Proposal
SOX	Sarbanes-Oxley
SSO	Standard Service Offer
UPIS	Utility Plant In Service
VVO	Volt VAR Optimization
WACC	Weighted average cost of capital

APPENDIX C: DATA REQUESTS AND INFORMATION PROVIDED

DR	Request
1-001	**PRIORITY DATA REQUEST**: Work Orders in DIR: Please provide in Microsoft Excel format a list of work orders by FERC account, including project identification numbers, that comprise plant to be recovered through Rider DIR for the period January 1, 2016, through December 31, 2016. Include the description, dollar amount, completion date, and whether the work was an addition or replacement. Please specifically identify blanket project work orders and associated project identification numbers.
1-002	**PRIORITY DATA REQUEST**: **DIR Filings**: Please provide, in electronic format, the schedules that support the Rider DIR filings for each quarter in 2016.
1-003	**PRIORITY DATA REQUEST: Rider DIR Preparation:** (a) Please provide a narrative of all changes, if any, from the prior year filing in how the Rider DIR is prepared. Include sources for all components, how components are gathered and entered, and approval requirements (i.e., who is authorized to approve, for what items are approvals needed, and when are approvals needed in the process). (b) Please provide any changes from the prior year filing regarding those persons who provide and/or compile information for the filing. Please provide the name, title, and department of each such person. Each person should be available for interview.
1-004	**DIR Filings:** Please provide, in electronic format, all workpapers and supporting documentation for the information included within the Rider DIR filings for each quarter in 2016.
1-005	**DIR Preparation:** Please provide a narrative of any changes made to the development process of the 2016 Rider DIR schedules from the 2015 schedules.
1-006	**DIR Workorder Population Recon:** Please provide a reconciliation of the list of workorders provided in Data Request 1.1 to the amounts included in the December 31, 2016, DIR Filing
1-007	**FERC Form 1 Recon:** Please provide a reconciliation of the Rider DIR balances to the balances in the 2016 FERC Form 1.
1-008	**Prior DIR Audit Adjustments and Recommendations:** For any and all 2015 audit adjustments or recommendations, please provide (1) the workpapers that support the adjustment amount recorded, and/or (2) the status of the recommendation.
1-009	**Organization Chart:** Please provide a current organization chart of the Company
1-010	**Policies and Procedures**: Please identify any and all changes since the prior year filing in the policies and procedures and/or flowcharts for the following activities that provide input into the Rider DIR revenue requirements and cost of service models. a) Plant Accounting, including 1. Capitalization 2. Preparation and approval of work orders 3. Recording of CWIP, including the systems that feed the CWIP trial balance; 4. Application of AFUDC 5. Recording and closing of additions, retirements, cost of removal and salvage to plant 6. Unitization process based on the retirement unit catalog 7. Application of depreciation 8. Contributions in Aid of Construction (CIAC) 9. Damage Claims. b) Purchasing/Procurement c) Accounts Payable/Disbursements d) Accounting/Journal Entries e) Payroll (direct charged and allocated) f) Taxes (Accumulated Deferred Income Tax, Federal, State, and local Income Tax)

DR	Request
	g) Insurance recovery h) Allocations i) Work Management System j) Information Technology
1-011	**Policies and Procedures**: Please specifically explain any changes since the prior year Rider DIR filling that have been made to the capitalization policies that would transfer costs from operating expense to capital. Include any changes to the retirement unit catalog.
1-012	**Policies and Procedures**: Please specifically explain any changes since the prior year Rider DIR filing in any of the policies and procedures that affect the Rider DIR revenue requirements and cost of service models that would have a bearing on any shift in the recording of costs from operating expense to capital.
1-013	**Approval Signatures:** Please provide the Level of Signature Authority (LOSA) document that supports the approval of capital projects put in service from January 1, 2016 through December 31, 2016. Please provide the titles and PRA Role for the employees who were listed as Required Signatures for the Funding and Approval on any of the projects
1-014	**Internal Audits**: Please provide a list of Internal Audits performed for 2016. List the name of the audit, scope, objective, and when the work was performed.
1-015	**SOX Compliance Audits**: Utility Plant In Service is fed from CWIP. Therefore, any system that feeds CWIP, including but not limited to WMS, Payroll, M&S, Overheads, AFUDC, Transportation, and direct contractor charges through purchasing, could have an impact on UPIS and, therefore, the DIR. (a) Please provide any SOX Compliance audits performed in 2016 on any of those feeder systems that in one form or another feed CWIP, or any other SOX compliance work that impacts the preparation of the DIR. Include whether the controls passed or failed and, if failed, the severity and impact of the failure on the DIR.
1-016	**Variance Analysis**: Please provide a Microsoft Excel spreadsheet in FERC Form 1 format (by FERC 300 account) of the beginning and ending period balances, additions, retirements, transfers, and adjustments for the period January 1, 2016, through December 31, 2016.
1-017	**Variance Analysis**: Please provide a Microsoft Excel spreadsheet of the jurisdictional accumulated reserve for depreciation balances by FERC 300 account for January 1, 2016, through December 31, 2016.
1-018	**Budget:** Please provide the 2016 capital budget supporting the plant spend in the 2016 DIR Compliance Filings. Also, please include the assumptions supporting the budget/projected data.
1-019	**Capital Dollars Spent:** Please provide the 2016 total actual capital dollars spent as compared to the approved budget.
1-020	**DIR Plan:** Please provide the 2016 DIR Plan provided to Staff showing the estimated and actual spend on Ohio Distribution plant
1-021	**DIR Plan Reconciliation to DIR Compliance Filing:** Please reconcile the DIR Plan provided to Staff to the capital dollars included within the DIR
1-022	**Variance**: Does the Company maintain any budget-to-actual and/or variance tracking from its 2016 DIR Work Plan Components to actual results for 2016? If not, please explain fully why not. If so, please provide the budget-to-actual and/or variance tracking for 2016, including any related Excel files and budget variance explanations.
1-023	**Depreciation:** Please provide any changes that have taken place in the approved depreciation accrual rates by FERC 300 account in 2016. Please indicate the Commission order that approved the rates for each company and the Service Company.
1-024	**Depreciation Study:** Was a Deprecation study conducted in 2016? If so, please provide that study covering Distribution Plant accounts.
1-025	Depreciation: Does the Company use a depreciation rate for any FERC 300 sub account hat has

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	not been approved by the Commission? If so, please provide the following for any changes made in 2016. (a) FERC 300 account, sub account (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
1-026	**ADIT**: Please provide a list of ADIT included within Rider DIR for 2016.
1-027	**ADIT**: Please provide a narrative of the type of ADIT eligible for inclusion in Rider DIR.
1-028	**ADIT**: The Tax Increase Prevention Act of 2014 extended the 50% bonus tax depreciation for qualified property placed into service before January 1, 2015. The Protecting Americans from Tax Hikes Act of 2015, further extended the 50% bonus tax depreciation for qualified property placed in service during 2015, 2016, and 2017. Please provide an explanation on how these tax provisions that extended 50% bonus tax depreciation for qualified property placed into service were recognized in the determination of ADIT in the 2016 Rider DCR filing.
1-029	**Renewable Tax Credits**: (a) During 2016, were any costs for any renewable projects included in any Plant Account 360 through 374 and recovered through the DIR? (b) If so, please identify the installed renewable projects and the costs recorded in each such Plant Account. (c) If any installed renewable projects were included, please provide the amount of any investment tax credits taken by the Company. (d) If any investment tax credits were taken by the Company for proj
1-030	**Carrying Charge Rate:** Please show in detail how the Company developed the carrying charge rate applicable in the Rider DIR for 2016. Include supporting Excel files showing the detail of carrying cost development for the return, depreciation, and property tax components. For each component, please state whether the amount is approved by the Commission and provide the Case Number and date of the Order.
1-031	**Gross-Up Factor**: Please provide the workpaper supporting the derivation of the Gross-Up Factor.
1-032	**Meters:** Please provide the quantity and cost of meters purchased during 2016. Please provide this information in total and for each type of meter.
1-033	**Meters**: Please explain how meters purchased are determined whether to be recovered through the DIR or through Gridsmart.
1-034	**Meters:** For the Smart meters purchased in 2016, please identify the number of meters purchased for gridSMART purposes and those purchased for non-gridSMART purposes (AMR or some other use). Also, please include the FERC plant account to which those respective meters were charged (e.g., FERC 370, FERC 370.16 or other FERC accounts).
1-035	**Meters**: Please confirm that meters are capitalized when purchased, as opposed to when installed. If this is not the case, please explain.
1-036	**Retired Meters**: Reference Case No. 13-1939-EL-RDR, Stipulation and Recommendation, dated April 7, 2016, pages 10-11: The Stipulation states that the Company will retire existing meters through the normal course of business which will be included in the DIR rider, and any undepreciated amount for the retired meters will be accorded standard accounting treatment and included in the calculation of accumulated depreciation reserve for distribution and general plant in the next base distribution case. How has the Company been recording and recovering the undepreciated costs of retired meters? How much has the Company recovered through the DIR? If individual assets are not tracked for mass property accounts, how is the amount of undepreciated costs recovered through the DIR determined. (a) Are meters

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	recorded by vintage year? (b) Are meters tracked by serial number? (c) If meters are recorded by vintage year and are tracked by serial number, can the accumulated depreciation be determined by the average unit cost by meter type multiplied by the depreciation rate multiplied by the number of years the asset has been in service? If not, why not?
1-037	**Riders/Surcharges:** Please provide a comprehensive list of Riders and surcharges that were in effect for the Company during 2016. Of the list of Riders, please indicate which, if any, provide for recovery of Distribution Plant. For each of those Riders, please show in detail how AEP coordinated cost recovery between them and Rider DIR. Include supporting workpapers.
1-038	**Exclusions:** Please provide project ID and a list of work orders by FERC account used for the following types of work in the testing period January 1, 2016, through December 31, 2016. (a) gridSMART (b) Enhanced Service Reliability Riders (ESRR)
1-039	**Exclusions for DIR:** Please provide a narrative of the distribution infrastructure to support customer demand and advanced technologies that is not eligible for inclusion in Rider DIR and the process that is used to identify and exclude these items from the Rider DIR calculations.
1-040	**gridSMART**: Please provide any changes in 2016 to the Company's policies and procedures and accounting guidelines for distinguishing which costs are (1) recovered in Rider DIR and (2) recovered in the gridSMART Rider.
1-041	**gridSMART**: Please show in detail specifically how costs related to Meters (account FERC 370 and sub accounts) and Communication Equipment (account FERC 397) are allocated between Rider DIR and gridSMART Rider.
1-042	**GridSMART**: Reference Case No. 13-1939-EL-RDR, Stipulation and Recommendation dated April 7, 2016, and Case No. 13-419-EL-RDR Order dated April 23, 2014: The Stipulation in Case No. 13-1939-EL-RDR (pp. 9–10) recommends that the capital costs associated with the approved gridSMART Phase I assets be transferred to the DIR for recovery. The Order in Case No. 13-419-EL-RDR (pp. 4–5) requires that upon a decision in Case No. 13-1939-EL- RDR, the DIR will be reduced by the net book value of 22,000 AMI meters, and those costs would be transferred to gridSMART Phase 2 Rider. Please provide a narrative of any changes from the last DIR review in 2015 on how that information will be pulled together, including the vintage years of the meters to be transferred, and the transfers recorded. If available, please provide the workpapers showing the accumulation of the costs associated with the transfer.
1-043	**Plant Held for Future Use**: Please provide a description of the item(s) included within the exclusion labeled Remove Plant for Future Use.
1-044	**In-active Work Orders:** Please provide an "inactive work order report" as of each date: (a) 12/31/15 (or 1/1/16) (b) 12/31/16
1-045	**Customer Bills**: Please provide a typical residential customer bill showing the application of the DIR for an illustrative month during 2016.
1-046	**Base Distribution Revenues**: Please provide screen shots of the query used to determine the base distribution revenues for each month of 2016 that can be used to verify the amounts of base distribution revenue included in the Company's quarterly DIR filings for 2016.
1-047	**Unitization Backlog**: Please provide information regarding any backlog in the unitization of work orders for 2016. Please provide the number of backlogged work orders, the dollar values of each, and the length of time for each in months.
1-048	**Insurance Recoveries:** Please provide a list of Insurance Recoveries charged to capital from January 1, 2016, through December 31, 2016. Please separate damage claim recoveries from

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	other recoveries.
1-049	**Insurance Recoveries:** Please provide a list with explanations of any 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. Please separate damage claim recoveries from other recoveries.
1-050	Blanket Work Orders: As was mentioned in the kick off meeting on April 13, 2017, please provide a detailed narrative of how blanket/project work orders are budgeted, approved, initiated, tracked, and closed. Include a discussion of any hierarchy (roll up) that exists between the work order and ultimate funding project. Please provide samples of documents to support the narrative.
2-001	Standard Cost: Blue Ridge understands the process of determining cost of removal of a retired AMI meter as follows: Cost to remove AMI meter = Bare labor cost + Fringe cost + Transportation cost Where, 1. Bare labor cost = standard labor time x indirect labor adder x standard bare labor rate 2. Fringe cost = bare labor cost x standard fringe factor 3. Transportation cost = bare labor cost x standard transportation factor (a) Is the process of determining cost of removal of a retired AMI meter the same for all meters (e.g., AMR and Electromechanical)? If not, please provide the formula differences and a narrative explanation. (b) Is the process of determining cost of removal of retired meters essentially the same for other equipment? If not, please provide the process. If not, please provide the formula differences and a narrative explanation.
2-002	Standard Cost: Regarding changes in the standard cost and standard cost process, please respond to the following: (a) How frequently is the standard cost process changed? (b) How frequently is the standard cost changed (i.e., labor rate, fringe factor, transportation factor)?
2-003	Standard Cost: Please provide the accounting detail for how the cost of removal amounts for replacement assets (including meters) is recorded. Please indicate timing and all accounts in the process, including moving from CWIP to the reserve.
2-004	Standard Costs: Is the process used for determining cost of removal for meters the same process as for setitng meters? If not, plealse provide a detailed explanation, including the details fo the accounting process.
2-005	Standard Cost: Is the bare labor costs included in the standard costs in conformance to labor contracts? If yes, please provide supporting documentation. If not, please provide detailed explanations of labor contract difference and reason for nonconformance.
2-006	Standard Cost: Please provide the calculation formula and a narrative explaining the indirect labor adder for removal of retired meters. (a) Is the indirect labor adder determined for cost of removal of retired meters different from the calculated indirect labor adder for removal of any other meters? If so, please explain. (b) Is the indirect labor adder determined for cost of removal of retired meters different from the calculated indirect labor adder for removal of any other equipment? If so, please explain.
2-007	Standard Cost: Please provide the calculation formula and a narrative explaining the standard fringe factor for removal of retired meters. (a) Is the standard fringe factor determined for cost of removal of retired meters different from the calculated standard fringe factor for removal of any other meters? If so, please explain. (b) Is the standard fringe factor determined for cost of removal of retired meters different from

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	the calculated standard fringe factor for removal of any other equipment? If so, please explain.
2-008	Standard Cost: Please provide the calculation formula and a narrative explaining the standard transportation factor for removal of retired meters. (a) Is the standard transportation factor determined for cost of removal of retired meters different from the calculated standard transportation factor for removal of any other meters? If so, please explain. (b) Is the standard transportation factor determined for cost of removal of retired meters different from the calculated standard transportation factor for removal of any other equipment? If so, please explain.
2-009	CWIP: Please provide the detail process for costs related to any feeder system that affects Distribution CWIP, including overheads, M&S and stores loading, transportation, etc.
2-010	**Cost of Removal/Standard Cost**: Please provide the method(s) and accounting used to charge cost of removal for the replacement of capital assets **other** than meters. If the cost of removal for other than meter capital assets is charged using a standard cost method, please provide the following information: a) Process formula for determining cost of removal b) Detailed narrative explanation of all elements of the process formula c) Are the labor costs included in these standard costs in conformance to labor contracts? If yes, please provide the supporting documentation. If not, please provide detailed explanations of differences and reasoned for nonconformance.
3-001	3-1. Priority Data Request - Reference Company response to BR-INT-1-001. Please refer to the attached list of work orders selected from the population of work orders provided in response to the reference data request. If you have any questions, please contact Joe Freedman at jfreedman@blueridgecs.com or 607-280-3737. In the interest of time, and associated deadlines, please provide the data in batches as they are completed. For each work order on the list, please provide the following information in Microsoft Excel spreadsheets: For the attached work order list (BRCS Set 3-2016 Sample Workorders 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.
4-001	Follow up to Data Request response BR-DR 1-001. The Company response indicated that work orders close to account FERC 106 or FERC 107 when they reach the In-Service status. Please

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	explain how work orders close to account FERC 107 (CWIP) when they reach in-service status.
4-002	Follow up to Data Request response BR-DR-1-014. The Company response appears incomplete. Blue Ridge asked for a list of internal audits performed for 2016. The Company response indicated that no DIR internal audits were performed in 2016. The DIR represents CWIP closed to plant. Therefore, any feeder system that charges Distribution work orders, such as Payroll, M&S, Transportation, overheads, contractors, etc., has costs closing to Plant in Service, which becomes part of the DIR. In consideration of the source of those costs, please provide a list of internal audits performed in 2016 that includes audits of any Company systems that feed CWIP. List the name of the audit, scope, objective, and when the work was performed.
4-003	Follow up to Data Request BR-DR-1-044. Inactive work order reports, attachments 1 and 2. Column N. a. Some of the work orders had a status of cancelled. Please provide the accounting for cancelling a work order. b. How does cancelling a work order affect the DIR?
4-004	Follow up to Data Request BR-DR-015, attachment 1. a. Please indicate if the controls for the SOX compliance work provided in the response passed or failed and, if failed, the severity and impact to the DIR of the failure. i. Allocations ii. Accounts Payable iii. Payroll b. Does the response include all SOX compliance work completed in 2016 related to any feeder system that supports distribution CWIP and UPIS? If not, please provide the same information for that compliance work as requested in BR-DR-015.
5-001	Standard Cost: Follow up to Data Request response DR-BR-2-006, b. The response indicates that for removal work related to other types of distribution plant assets, the indirect labor multiplier is based on a crew of three laborers and a qualified observer. a. Does all removal work use the same size crew? If not, please indicate what the crew size is based on the type of removal work. b. If the crew size changes, does that change the Company response to part b? If so, please provide the updated response. c. What does a qualified observer mean? d. What job description(s) is associated with a qualified observer? e. If a qualified observer is a union employee, please indicate the position(s) and wage level (rate). f. If the qualified observer is a management employee (salaried), please provide the title of those that perform this function. g. If a qualified observer can be from a range of different union and/or management positions is the indirect labor adder adjusted accordingly? If not, why not?
5-002	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 that the assets have been installed per the work order scope and description. The work order/project selection criteria were primarily 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. a. An individual(s) that can coordinate all the field verification with Staff b. Representatives from FE that can field assist Staff at each field location c. The Project Manager or a person that was responsible for the work on each project available

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	to answer Staff's questions d. Schematics/drawings or any other visual diagram that indicates 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 (labor, Material, equipment) If AEP 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 i. Work Order: 42244260 –KILLBUCK - Construct 9.275 MVA Dist. Station 1. Project ID: 42244260 2. Cost: $2,838,671.28 ii. Work Order: 42263333 – DENNISON, replace 10.5 MVA XFMR with 20 MVA 1. Project ID: 42263333 2. Cost: $3,645,031.50 iii. Work Order: 42393169 – Barnesville, replace control building 1. Project ID: 42393169 2. Cost: $595,677.36 iv. Work Order: 42473073 – Spare 50MVA 138/34.5/13.8 kv Auto Bixby 1. Project ID: 42473073 2. Cost: $735,842.03 v. Work Order 42453369 – BANE Stn, Install a 69-12kv DIST XFMR to service AUGUSTA 1. Project ID: 42453369 2. Cost: $1,235,783.75. vi. Work Order: T0162301 – HIGHLAND (CS) Replace failed 13KV CB's 26 and 27 CAP Proj 1. Project ID: T0162301
5-003	Policies and Procedures: Follow-up to DRs 1-12 and 1-13. The response to DR 1-12 provides a list of policies and procedures changes that affect the Rider DIR. The response to DR 1-13 was the document that provides the Level of Signature Authority that supports the approval of capital projects put in service in 2015. Based on the Company's comments to recommendation #4 of the 2015 DIR Compliance Audit stating "The Company no longer uses the Lotus Notes database for approvals," please provide responses to the following items: a. When did the change from Lotus Notes to another project approval method take place? b. Is the change documented? In other words, has the document submitted as a response to DR 1-13 (i.e., Distribution Business Rules for Authorizing Capital Projects) been updated to reflect the approval change? c. Please provide a copy of the updated Distribution Business Rules for Authorizing Capital Projects d. The concern in recommendation #4 was that project approval documentation reviewed in the audit included several instances where the documentation was incomplete for both blanket and specific work orders. In these cases, the documentation was not signed, and it did not indicate that the approval process was used. Does the Lotus Notes database replacement offer a corrective to the problem identified in the audit?
6-001	Follow-up to Data Request response 4-002, attachment 1. Please provide the summary findings and recommendations for the following audits: a. Cost capitalization Data Analytics Review. Audit report date: November 2016. b. Canton allocations – Labor, comparable units, stores, intercompany and building/telephone. Audit report date: May 2016. c. Service Company Cost Allocations Review. Audit report date: July 2016.
6-002	Follow-up to Data Request Response 3-001, Attachments, 9,10,11,12, and 13. Please confirm

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	that the above-referenced response is the same as what was provided by the Company in preliminary response 3-1-d, e, f, and g in form and in content. If not, please explain the specific differences. a. Blue Ridge Data Request 3-001, attachment 9 for transfers of plant from general ledger account 106 to 101 (preliminary response 3-1-d). b. Blue Ridge Data Request 3-001, attachment 10 for detail for the cost of removal and salvage value for retirements (preliminary response 3-1-e). c. Blue Ridge Data Request 3-001, attachment 11 for detail of retirements from Account 101—Continuing Property Records (preliminary response 3-1-e). d. Blue Ridge Data Request 3-001, attachment 12 for a description of cost elements (preliminary response 3-1-f). e. Blue Ridge Data Request 3-001, attachment 13 for detail for workorders by cost elements (preliminary response 3-1-g).
6-003	Follow-up to Data Request Response 3-001 Attachment 13, supporting detail for cost elements, work order 42365009, line 4865. Please explain the MMS Stock General of $(803,866).
6-004	Follow-up to Data Request Response 1-001, Attachment 1 and Data Request Response 3-001 Attachment 13 (supporting detail for cost elements) work order W0023969 –106 reversal, AMI meter blanket. The work order sample cost is $1,291,692.89 (BR-DR-1.001, Attachment 1) but the work order detail indicates $1,077,897.02. Please explain the $206,055.88 difference found in preliminary 3-1-g.
6-005	Follow-up to Data Request Response 3-001, Attachment 1, work order sample summary. Please explain why that work orders W0027041 and W0025973 – Forestry Program are not part of Vegetation Management, which should be excluded from the DIR.
6-006	Follow-up to Data Request Response 3-001, Attachment 1. Work order DOP0211568 – 106 reversal, public relocation project – record purposes. Please identify the link between the work order and the project in Attachment 1
6-007	Follow-up to Data Request Response 3-001, Attachment 2 (page 3 of 13). Program DISTBLKOP. The customer service segment of the project was over budget by 18%. Please provide the detailed reason for being over budget .
6-008	Follow-up to Data Request Response 3-001, Attachment 8. Work order DOP0244155 – Equipment removal Columbus convention center. Please explain why this work order had a credit balance of $(264,905.36).
6-009	Follow-up to Data Request response 3-001 – Work order Sample and Attachment 6. The following programs, projects, and work orders were for the purchase of Capital Spares. Please explain why the purchase of capital spares qualifies for inclusion in the DIR. Also, please explain why the purchase of capital spares is considered “used and useful.” a. Program: TA2012102, Project A12102584, work order 42473073 – Spare MVA 138/34.5/13.8 KV Auto Bixby - $735,842.03. Total program: $13,325,798. b. Program: TA2016913, Project A12102574, work order 42431638 – Spare MVA 138/69/13.09 - $554,237.70. Total Program: $16,009,205. c. Program: TA2012102, Project A12102568, work order 42412188 – WACO Spare 20 MVA 238/13.09 KV LTC - $570,122.30. Total Program: $13,335,798.

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6-010	Follow-up to Data Request Response 3-001 – Work Order sample and Attachments 1 and 6 a. Attachment 6, page 1 of 160: Program DR14A0001, Project DR14A030, work order 42244260 – KILLBUCK, construct 9.375 MVA Dist. Station - $2,838,671. The Company revised the cost of the project by $339,497. Please explain why the distribution work orders written by the contractor were insufficient to describe scope and had to be rewritten by AEP. Also, what was the necessary contractor change(s) that resulted in increased cost? b. Attachment 6, page 119 of 160, Program (DN15NWMON), Project, P15050007, work order 42487877 - SPARTA SWITCH: SPARTA PUMPING METERING - $459,359.38. Please supply the benefit/cost analysis and any other supporting documentation for the selection of the Fiber Optic alternative. c. Attachment 6, pages 37 and 41 of 160. Program TA2013003 Project A13003211, work order 42393169 - $595,677.36 and 42440744 - $594,770.60. Ohio 2013/2014 Asset Replacement and Refurbishment Program. The Company authorized $10,357,900 for this Program. The object of the program was to improve system reliability and dependability by replacing failed assets, assets in danger of imminent failure, and selected obsolete assets. Did the portion of the project related to Distribution result in improved system reliability? If so, please respond to the following requests: i. Please provide documentation that supports that conclusion. ii. If system reliability did not improve, please explain why it did not. d. Attachment 6, page 140 of 160, Program TBLANKTOP, project S1250OHE, work order T0154738. Project is Transmission capital blanket revision but includes Distribution of $5,437,199. This program went from an original authorized amount of $1,124,006 to $5,437,199, or an increase of 382%. The explanation was for customer service projects including facilities for new customers. i. Please supply supporting information of what types of customer service projects took place and what facilities were provided to the customers. ii. If the project resulted in new customers, please indicate the number of new customers added and the annual increase in revenues.
6-011	Follow up to Data Request response 3-001 – work order sample and attachments 2 page 3 of 13. Program: DISTBKLOP Projects: EON014649, EDN100031 and DP15W01F0, Work orders: BOP000001, DOP0233014 and DOP0244155. The Transformer blanket was over budget by 29% ($5.6m) and the Customer Service blanket was over budget by 18% ($3.8m). Please provide the detailed reasons those two blanket projects were over budget.
6-012	Follow up to Data Request response 3-001 – work order sample and Attachment 3 (page 5 of 7) Program: DISTGMOH, Projects: EDN100031 and EDN014678, work orders: DOP0250402, DOP0247782 and DOP0250402. – Distribution Annual Programs. The Pole Replacement blanket was over budget by 89% ($8.8m) and the Sectionalizing blanket was over budget by 33% ($.3m). Please provide the detailed reasons those two blanket projects were over budget.
7-001	Variance Analysis: The Company's 2016 FERC Form 1 shows the end-of-year balance for account 362 as $669,149,117. The Company's DIR December 2016 book cost balance for utility accounts 36200 totals 669,147,879.68 (see Company's response to Blue Ridge data request 1-002, Attachment 4, tab DIR NBV, Column D, Rows 9 and 10). Please provide an explanation for the approximate $1,237 difference.
7-002	Variance Analysis: Follow-up to response to BR 1-016, Attachment 1. Please provide a detailed explanation for the transfer/adjustment of $262,942 increasing the account 360 Land balance.
7-003	Variance Analysis: Follow-up to response to BR 1-016, Attachment 1. Please provide detailed explanations for the significantly larger addition over retirement for the following accounts:

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	a. Account 360: Additions $1,825,470 and Retirements $0 b. Account 362: Additions $33,816,532 and Retirements $3,668,217 c. Account 366: Additions $23,310,992 and Retirements $89,715 d. Account 367: Additions $39,422,294 and Retirements $7,621,908
7-004	Variance Analysis: Follow-up to response to BR 1-016, Attachment 1. Please provide detailed explanations for the increase in 2016 Additions—$23,310,992—over the 2015 Additions—$5,332,748—for account 366.
7-005	Base Distribution Revenue: Follow up to BR-DR-1-046. Please provide the Base Distribution Revenues for the December 2016 filing.
7-006	Base Distribution Revenue: Follow up to BR-DR-1-046. a. Please explain why the June and September Base Distribution Revenue required an exclusion for the reactive demand of Ohio Power Company rate zone. b. Why was the exclusion was not required for March 2016 and December 2016? c. What is equation code RD06?
8-001	Follow up to Data Request response 3-001, attachment 6, page 5 of 160: Work Order: 42244260 – Construct 9.275 MVA Dist. Station. Project ID: 42244260 -Cost: $2,838,671.28. The project justification concluded that rebuilding the Killbuck Station was the most cost effective alternate. a. Did the Company estimate the alternative cost of finding another location? If not, why not? b. How did the Company determine that the savings in funds associated with maintaining the platform will be realized by the retirement of the station? What are those estimated savings? c. Did the Company calculate the payback period for the alternatives considered? If not, why not? If so, please provide that payback calculation.
8-002	Follow up to Data Request response 3-001, attachment 6, page 13 of 160 - Work Order: 42263333 – DENNISON, replace 10.5 MVA XFMR with 20 MVA. Project ID: 42263333 Cost: $3,645,031.50. Were cost estimated prepared for other alternatives? If so, please provide those calculations? If not, please explain why?
8-003	Follow up to Data Request response 3-001, attachment 6, page 40 of 160, Work Order: 42393169 – Barnesville, replace control building, Project ID: 42393169. Cost: $595,677.36. a. Please provide the cost benefit analysis that supports the replacement of the control building. b. Please provide the estimated payback period for the funds expended. c. Please provide the cost benefit analysis for the other alternatives considered.
8-004	Follow up to Data Request response 3-001, attachment 6, Work Order: 42473073 – Spare 50MVA 138/34.5/13.8 kV Auto Bixby, Project ID: 42473073, $735,842.03. a. What is the estimated lead time associated with purchasing a Spare 50MVA Transformer? b. Were other alternatives considered such as using a mobile substation or an agreement with another utility to borrow a transformer? If so, please provide the detail for those alternatives. If other options were not considered, why not? c. How does this become the lowest cost alternative for the ratepayer?
8-005	Follow up to Data Request response 3-001, attachment 6, page 88 of 160, Work Order 42453369 – BANE Stn, Install a 69-12kv DIST XFMR to service AUGUSTA, Project ID: 42453369 Cost: $1,235,783.75. a. Did the Company perform a cost benefit analysis on the other alternative of 138KV conversion? If so, please provide a comparative cost of the alternative selected. b. Did the Company calculate a payback period and/or rate of return for the option selected? If so, provide that analysis. If not, why not?

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	c. Did the Company experience load growth as a result of the 69kv transformer? d. Please explain how a 69kv transformer is considered a Distribution asset.
8-006	Follow up to Data Request response 3-001, attachment 6, page 150 of 160, Work Order: T0162301 – Replace failed 13KV CB's 26 and 27, Project ID: T0162301, Cost: $270,900.54. Did the Company prepare a cost comparison of the alternatives including payback period, internal rate of return, or any other cost type analysis? If so, please provide. If not, why not?
8-007	Reference Company's Initial Comments and Reply Comments regarding Blue Ridge's recommendations 7 and 8: Recommendation 7 from Case No. 16-0021-EL-RDR. In summary, Blue Ridge recommended that the Company demonstrate to the Commission that the purchase of meters on work order 7900299 from an AEP affiliate represents the lowest cost alternative to the Company and that the Company provide a comparison of the actual meter costs (without the capitalized labor or other installation costs) with other similar meter type costs, supporting the fact that this purchase was in line with other similar purchases. The Company's reply comments did provide information, but the information provided does not answer the basic question, are affiliate purchases the lowest cost alternative. The Company initial response to Blue Ridge's Recommendations 7 and 8 stated: o The Company would work with Staff; o The Commission is aware of the process and benefits of the Company implementing the affiliated transaction agreement. o The Company provided benefits to the project by utilizing the affiliated transaction agreement to sell at net book value the meters removed throughout the territory related to the gridSMART Phase I rollout. In reply comments the Company provided additional information: o That the Ohio customers saved approximately $64,000 for affiliate meter purchases in 2015 o The Company provided the cost per meter for three work orders, including the work order cited by Blue Ridge. o The Company provided the average cost per unit for the specific work order in question based on a random sampling of two months of invoices. o Because of confidentiality, the Company stated it will provide a summary of the items purchased as well as purchase price. Those invoices can be reviewed if the Commission determines greater detail is needed. o The Company indicates that meter transformers are capitalized to the meter account as well. The Company response to the 2015 Data Request 7-018 indicated that Ohio Power purchased meters from the following affiliates: • AEP Texas North • Appalachian Power Co. • Indiana & Michigan Co. • Kentucky Power Co. • Public Service Co. of Oklahoma • Southwestern Electric Power Co. • Wheeling Power Co. a. Please indicate whether the affiliates was regulated or a non-regulated entity? b. Please provide a schedule that lists the meters purchased from affiliates on work order

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	7900299 and the associated net book value for those purchases on a unit cost basis by meter type. c. Provide a schedule on the same basis, by meter type by unit cost of what the same meters would cost on the market from the suppliers that the Company used (or would have used) in 2015 to purchase meters. d. Compare the 2 schedules and determine the net savings/detriment to the customer by purchasing meters from affiliates. e. Please provide any analysis performed to ensure that the purchase of the meters from an affiliate were in compliance with the affiliate transaction rules. f. Were the meters purchased from the affiliate new or used? g. If new, were they stock meters (not in the field) and being depreciated?
8-008	gridSMART II (Recovered through GS Rider): Reference BR-1-002, Attachments 4. a. Please provide a reconciliation of the gridSMART II Net Plant excluded from the Rider DIR to the gridSMART II Net Plant recovered through the GS Rider. b. Please provide copies of the gridSMART Rider filing that supports the amounts excluded in the Rider DIR. c. The assumption is that the year end Net Plant balance excluded in Rider DIR should match the gridSMART II Net Plant recovered through Rider GS. If this is not the case, please explain.
8-009	Incremental Veg Mgmt (Recovered through Rider): Reference BR-1-002, Attachments 4. a. Please provide a reconciliation of the Incremental Veg Mgmt Net Plant excluded from the Rider DIR to the Incremental Veg Mgmt Net Plant recovered through the Rider ESSR. b. Please provide copies of the Incremental Veg Mgmt Rider filing that supports the amounts excluded in the Rider DIR. c. The assumption is that the year end Net Plant balance excluded in Rider DIR should match the Incremental Veg Mgmt Net Plant recovered through Rider ESSR. If this is not the case, please explain.
9-001	ADIT: Reference BR-DR-1-002 Attachment 3 and Attachment 4. Please explain why the Actual ADIT Book Balance at 9/1/16, ($702,737,409) dropped as of 12/31/16 to $694,575,485.
9-002	ADIT: Reference BR-DR-1-026, Attachment 1. Please provide an explanation of each of the following ADIT items included in Account 282.1 and how it is related to utility perty of the distribution function. a. SYD BENEFIT NORMALIZED b. CLS LIFE DEPR (ADR) - REG c. CLS LIFE DEPR (ADR) - ADD FRWD d. ACRS BENEFIT NORMALIZED e. SEC 481 LEAD/LAG TAX DEPRECIATION f. CAPITALIZED INTEREST - SECTION 481(a) CHANGE IN METHOD g. RELOCATION COSTS - SECTION 481(a) CHANGE IN METHOD h. R & D DEDUCTION - SECTION 174 i. BOOK PLANT IN SERVICE - SFAS 143 - ARO j. DEFD FIT BENEFIT - PROP RETIREMENTS k. ABFUDC l. ABFUDC - SMART HOUSE m. SEC 481 PENS/OPEB ADJUST n. PERCENT REPAIR ALLOWANCE o. CAPITALIZED RELOCATION COSTS p. REMOVAL COSTS

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10-001	Meters: Follow up to data response BR-DR-1-032. Please refer to the table above. a. Define PRU_NBR. b. Fill in the table with the description of each of the Device Codes including the brand name. c. Fill in the table with whether the meter is used in non gridSMART purposes, gridSMART Phase I, gridSMART Phase II, Code Red, or Other (please describe Other). d. Fill in the table with how the Company recovers the cost of the meter purchase (for example, DIR, gridSMART, etc.)
10-002	Meters: Follow up to data response BR-DR-1-032. Please refer to the table above. a. Please provide the cost for each Device Code purchased under PRU_NBR 7007, 7008, and 7009. b. For each PRU_NBR that includes purchases, please provide the vendor or source and price for each type of meter purchased. c. For each PRU_NBR, where is the Company recovering the costs associated with this purchase? d. Are PRU_NBR 7301 purchases gridSMART meters? If so, how many of the 12,176 meters are included in gridSMART I? How many are included in gridSMART II? e. For PRU_NBR 7302, purchases gridSMART meters? If so, how many of the 1,002 meters are included in gridSMART I? How many are included in gridSMART II?
10-003	Meters: Follow up to data response BR-DR-1-032. a. Please provide the PRU_NBR and Device Code of the Nighthawk meters. b. Please provide how many Nighthawk meters have been purchases, when they were purchased, and the unit price. c. How is the Nighthawk meter used? d. How are the costs of the Nighthawk meter recovered?
10-004	Meters: Follow up to data response BR-DR-1-032. a. Please provide the PRU_NBR and Device Code of the micro AP meters. b. Please provide how many micro AP meters have been purchases, when they were purchased, and the unit price. c. How is the micro AP meter used? d. How are the costs of the micro AP meter recovered?
11-001	Capital Spares: Follow up to Data Request response 6-009, parts 1, 2, 3. The request asked why the Capital Spares should be included in the DIR and why the Company considered them used and useful. The Company response cited the spare part capitalization policy, which allows the Capital Spares to be included in Utility Plant in Service, and why they are necessary. However, the Company did not address why Capital Spare parts are considered used and useful and should be included in Rider. a) Please provide a detailed explanation of why the Company believes Capital Spares are considered used and useful. b) Please provide a detailed explanation of why the Company believes purchase of Capital Spares should be included in the DIR. Provide the provision(s) in Commission Orders related to the DIR, as support.
11-002	<u>**Budget vs. Actual**</u>: Follow up to Data Request 6-011, part 1. The explanation of why the Customer Service were over budget was vague. a) Customer Service Blankets: Please explain in further detail why the “Projects in this component are subject to the construction schedule of the party requesting the work” would cause the Customer Service Blanket to be over budget by

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	18%
11-003	Budget vs. Actual: Follow up to Data Request 6-011, part 2. The explanation of why the Transformer Blankets were over budget was vague. a) Please explain in further detail why "this component is subject to customer activity and the need to maintain adequate inventory" would result in Transformer Blankets to be over budget by 29% b) Please explain how customer activity affects Transformer blankets. c) What percentage of the over budget of 29% for the Transformer blanket has to do with the need to maintain an adequate inventory of Transformers. 4) Budget vs. Actual: Follow up to Data Request 6-012 part (1).
11-004	Budget vs. Actual: Follow up to Data Request 6-012 part (1). a) Please provide additional detail on why "2016 additional replacements were performed to meet the requirements that were not originally contemplated in the 2016 work plan for this program." b) Why was the Pole Replacement budget developed prior to the Development of the 2016 work plan? c) Is the development of Capital budget programs typically done before the development of the work plans?
11-005	Retirements: Follow up to Company response to Data Request 3-001, work order sample summary and 3-001, attachment 10 and 11, Retirements. The following work orders appear to be replacement projects. Please explain why the Company did not record retirements. a) Work order DOP0251907 – 61176824, Replace A&C Regulators and all 3 bypass switches b) Work order DOP0258779 – 62917111F-2013. TV141E, protector Chg out
11-006	6) Incentives: Reference Company response to Data Request 3-001, attachments 12 and 13. The following work orders had one or more of the cost codes listed below charged totaling $138,511. Please explain how the cost codes charged benefit the ratepayer and why they should be included in the DIR. If the Commission has allowed such charges in the past, please provide the provision(s) within Commissioner's Orders that allowed such inclusion. • Cost Code 141 – Incentive Actual Dept. Level • Cost Code 143 – Other Lump Sum Payments • Cost Code 145 – Stock based Compensation • Cost Code 154 – Restricted Stock Incentives • Cost Code 156 – Transmission Incentives Work Orders: i) Work Order 42244260 ii) Work Order 42440744 iii) Work Order BOP0000001 iv) Work Order DOP0198596 v) Work Order DOP0227970 vi) Work Order DOP0243317 vii) Work Order DOP0251907 viii) Work Order DOP0252967 ix) Work Order DOP0254346 x) Work Order DOP0258779 xi) Work Order W0025973 xii) Work Order W0027041

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12-001	Standard Costs: Follow up to response to 2-001. Please provide the 2016 amount used and the supporting documentation used to determine that amount for each of the following standard cost components: a. Indirect Labor Adder b. Standard Fringe Factor c. Standard Transportation Factor
12-002	Please provide a list of Vegetation Management Capital workorders associated with the ESRR exclusion in the DIR.

APPENDIX D: WORK PAPERS

Blue Ridge's workpapers are available on a compact diskette (CD) and were delivered to the PUCO Staff per the RFP requirements. Workpapers that support Blue Ridge's analysis are listed below.

- WP - List of Spares and Mobile Subs from Population.xlsx
- WP 2016 DIR Tables for Report.xlsx
- WP ADIT BR-DR-1-026_Attachment_1.xls
- WP AEP-Ohio - Extrapolated Incentive Comp Cost Codes-2016
- WP BR-DR-1-001 Attachment 1 - CHECK
- WP BR-DR-1-001 Attachment 1 - Sample Pulled
- WP BR-DR-1-002_Attachment_1 thru 3 Sample Size Calculations
- WP BR-INT-2-001 Attachment 8
- WP BRCS AEP 2016 DIR Audit Workorder Testing Matrix FINAL
- WP Insurance BR-DR-1-048_Attachment_1.xlsx
- WP Insurance Pending BR-DR-1-049_Attachment_1.xlsx
- WP Standard Cost to Labor Contract Comparison BR_DR_2-005 COMPETITIVELY SENSITIVE CONFIDENTIAL Attachment.xlsx
- WP V&V DIR Model BR-DR-1-002_Attachment_4.xlsx

In regard to Rider DIR, the personnel listed in the following table had key roles when interviews were conducted in 2013. Those Interview Notes were provided in Blue Ridge's previous audit workpapers. While titles have changed, all these individuals except one maintained their roles in supporting the DIR. The one difference is in regard to Property Accounting Manager. Janet Swanger is no longer in that position. Blue Ridge interviewed David Hummel and Thomas Sulhan, both Managers of Property Accounting, for the current audit. The Interview Notes for their interview are included in this year's audit workpapers.

Table 16: AEP-Ohio Personnel Interviewed in 2013

#	Name	Position
1	Andrea Moore	Director Regulatory Services
2	Jack Kincaid	Accounting Operations Senior Manager
3	Shannon Liggett	Allocations Manager
4	Judson Schumacher	Director T&D Procurement
5	Janet Swanger	Property Accounting Manager
6	Joel Trad	Director Distribution Engineering
7	John Woellert	Administrator Regulatory Assets

Table 17: AEP-Ohio Personnel Interviewed in 2017

#	Name	Position
1	David Hummel	Managers of Property Accounting
2	Thomas Sulhan	Managers of Property Accounting