Case No. 17-2202-GA-ALT

Prudence Audit of
Plant in Service and Capital Expenditure Program Spending
For Columbia Gas of Ohio, Inc.

Submitted on September 3, 2018

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TABLE OF CONTENTS

TABLES

FIGURES

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.

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ORGANIZATION OF BLUE RIDGE'S REPORT

This report is organized according to the following major sections:

- *Executive Summary*: This section provides a summary of Blue Ridge's observations, findings, conclusions, and recommendations presented in more detail in the body of the report.
- *Elements of Analysis*: This section provides the following elements used in Blue Ridge's analysis: background; project purpose; project scope; audit standard; materiality; information reviewed; and interviews and field observations.
- *Project Requirements and Related Summary Conclusions*: This section identifies the requirements of the Request for Proposal for this project and specifies Blue Ridge's summary conclusions regarding those requirements.
- *Detailed Analysis, Findings, and Recommendations*: This section documents Blue Ridge's analyses that led to our observations, findings, and recommendations regarding the plant-in-service balances and the Capital Expenditures Program (CEP). It includes the rationale and description of any recommended adjustments.
- *Appendices*: The appendices include information reviewed and workpapers that support recommended adjustments. Also included are the recast plant-in-service schedules (B-Schedules).

EXECUTIVE SUMMARY

On December 1, 2017, Columbia Gas of Ohio, Inc. ("Columbia" or "Company") filed an application seeking authority from the Public Utilities Commission of Ohio (PUCO or "Commission") for a new alternative rate plan to establish a capital expenditure program (CEP) rider ("CEP Rider"). The Company filed an amended application on April 2, 2018. The Company stated that the purpose of the CEP Rider is to recover the post-in-service carrying costs, incremental depreciation expense, and property tax expense currently deferred pursuant to Columbia's capital expenditure program deferral ("CEP Deferral") as well as the corresponding assets to which these expenses are directly attributable in the capital expenditure program.

The Public Utilities Commission of Ohio (Commission or PUCO) issued a request for proposal seeking proposals to conduct a two-part audit of Columbia's CEP capital expenditures. The first part of the audit is to review and attest to the accounting accuracy and used and useful nature of Columbia's non-IRP capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (December 31, 2007 as set in Case No. 08-072-GA-AIR, et al) through December 31, 2017. The second part of the audit is to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2017.[1] Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the review. Blue Ridge's investigation included data requests, interviews, field inspections, and analyses, including variance analysis and detailed transactional testing.

Part 1 Plant In-Service Balances

In regard to the first part of the audit—concerning the accounting accuracy and used and useful nature of Columbia's non-IRP capital expenditures and related assets and corresponding depreciation reserve since the last base rate case—Blue Ridge's investigation identified three recommended adjustments that should be applied to the plant-in-service schedules and their associated depreciation reserve balances. These adjustments are addressed throughout the report. The effect of our adjustments reduces net plant by $224,138. Blue Ridge's recommended adjustments have been included in the recast plant-in-service schedules that are provided in Appendix D.

Through our analysis, Blue Ridge found that the Company was able to provide detailed continuing property records to support its plant in service balances. For the work order / projects detail that the Company provided, Blue Ridge performed detailed transactional testing. The results of this analysis are discussed in this report's Detailed Transactional Testing subsection. Through our transactional detail testing (Step T3), Blue Ridge found that all the work included in the projects sampled are capital in nature, and the scope of work and cost detail coincided with the applicable FERC 300 accounts to which the work applies in accordance with the FERC Uniform System of Accounts (CFR 18). The projects were classified to the proper intangible, distribution, and general equipment FERC accounts.

However, Blue Ridge noted that the Company moves meters from inside to outside residences, which is typically charged as an expense. When relocating meters is done in conjunction with service-line replacements, the Company capitalizes the entire activity. While we do not disagree with the Company's process, it does give latitude to not relocate meters until service lines are replaced. The

[1] Case No. 17-2202-GA-ALT Request for Proposal No. RA18-CSPA-1, pages 1-2.

Company does not track the meters relocated on an annual basis and, therefore, does not know the cost, including installation, for relocated meters expensed and capitalized. Blue Ridge recommends that this activity be tracked more closely so that the Company can demonstrate why the cost of meters moved from inside to outside should be capital and included in the CEP.

Blue Ridge also found that the Company "calculates incremental revenue by identifying increases/decreases in the annual average number of customers served by rate schedule since its last rate case. Columbia uses average number of customers rather than monthly change in accordance with an agreement with Commission Staff. At that time, using average number of customers was determined to be the best approach since it eliminated seasonal fluctuations. These variances in customer counts are then multiplied by a calculated average of non-equity revenue generated under that rate schedule and aggregated to determine the incremental change in revenue." However, subsequent follow-up resulted in the Company developing a more precise calculation by rate schedule and discovering a potential offset during calendar year 2015. The Company stated, and Blue Ridge recommends, that it work with Staff to review this calculation and incorporate any necessary offset.

The depreciation rates in use were approved by the Commission in Case No. 08-72-GA-AIR over ten years ago. Blue Ridge recommends that a depreciation study be performed, reflecting the numerous subaccounts that have been added since the last case, and rates be updated. The Company explained that depreciation accrual rates included in Schedule B-3.2 are calculated average depreciation rates for the FERC account. The Commission-approved rates are utilized at the sub-FERC account level, which arrives at the calculated average rate for the FERC account. The Company's explanation is not unreasonable.

To calculate depreciation expense in the CEP deferral, the Company uses a composite depreciation rate. The Company provided the calculations of the composite depreciation rates since the inception of the CEP deferral. Blue Ridge compared the calculated composite rate to the rate used in the Annual Information filings and found several inconsistencies. The inconsistent use of the calculated composite depreciation rate results in a misstatement of the CEP depreciation expense and the resultant reserve for depreciation. Blue Ridge recommends that the Company work with Staff to review the depreciation expense and the resultant reserve for depreciation calculation and incorporate any necessary adjustment. The composite rate has no effect on the roll-forward balances, as those are related on FERC-account-specific depreciation accrual rates. Blue Ridge found that the CEP Deferral depreciation reserve reflects the cumulative depreciation expense since the CEP inception as calculated using a composite depreciation rate. The reserve was not provided on a FERC account basis and is not based on the balances within the Company's books and records. The Company agreed to work with Staff to provide non-IRP gross plant and reserve balances by FERC account.

For field inspections, Blue Ridge selected 11 locations, several with multiple assets. An additional 13 projects were selected for desktop review. Blue Ridge concluded that the assets were used and useful and provide benefit to the ratepayer. The assets did not appear over built. Company personnel appeared knowledgeable about the projects.

Desktop reviews performed determined that the Company had adequate supporting documentation for the projects, including the appropriate engineering detail. The projects appeared to have been adequately planned with alternatives vetted. As a result, the projects are used and useful and providing benefit to the ratepayers.

Part 2 Capital Expenditures Prudence Audit

For the second part of the audit, Blue Ridge purposed, as the RFP instructed, "to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2017."

Other than three recommended adjustments associated with cost overruns for which the Company was unable to provide documentation fully explaining the overrun, Blue Ridge found nothing to indicate that the non-IRP capital expenses and assets for the period January 1, 2008, through December 31, 2017, were unnecessary, unreasonable, or imprudent. The necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures was considered throughout the entire audit, including the variance analysis, transactional testing, and physical inspections and desktop reviews.

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as not to adversely affect the balances in distribution utility net plant in service. Blue Ridge also reviewed internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits.

A few significant events occurred during the scope period of this audit. Most were in regard to software (PeopleSoft and PowerPlant) implementation and/or upgrades. Another significant event, the NiSource separation into two distinct energy infrastructure companies: a fully regulated natural gas and electric utilities company (NiSource) and a natural gas pipeline, midstream, and storage company (Columbia Pipeline Group) in 2015, had no resultant impact on Columbia's plant balances.

At the time of the 2015 NiSource separation, Columbia's capitalization policy was reviewed and consolidated with all other local distribution companies at NiSource to form a NiSource-wide Plant Capitalization Policy. No major changes were made to Columbia's application of the policy as a result of this review and consolidation activity. There were, however, changes related to the Software Capitalization Policy in order to create one consistent threshold for utilization across all NiSource companies.

Blue Ridge concluded that Columbia's controls were adequate and not unreasonable. Furthermore, we were satisfied with actions taken with regard to internal and other audits reviewed.

Capital spending has increased significantly since the inception of the CEP. The Company identified pressures on its capital budgets due to a constrained labor market, and increased restoration requirements and permitting fees for local and state government, as well as an increase in the volume of required relocation work. There also have been large Shared Services projects, such as the new Arena headquarters in 2014 and the information technology system upgrades in 2017. However, Growth-related activities is the largest annual spend category.

Starting in 2012 (the first full year of the CEP), the actual spend on growth increased 63%. That trend continues through 2017 with a combined 149.5% increase from 2012 through 2017. Certain areas of the Company service territory have seen steady growth, which would contribute to the need for more spending. Growth-related activities are driven, as expected, by service and main pipe-related activities. Labor costs are the major contributor to the CEP costs. Contractor costs have affected the annual cost per total mile of main.

The CEP costs are increasing. Part of the reason is the extent of work going on, and part of it has to do with rising contractor costs. Labor costs are a significant driver of the increasing costs of the non-IRP projects. The demand for qualified crews is increasing while the supply is decreasing. Contractor constraints are expected to continue in the foreseeable future. The Company understands the key labor cost drivers and provided steps it is taking to control those costs. The actions taken by Columbia are discussed in detail in the section identified as Cost Containment. Blue Ridge concludes that the Company is implementing sound cost containment strategies. But although those strategies may be slowing the impact, they are not negating the fact that the Ohio pipe construction market is a constrained market, as are also the neighboring states which also have accelerated capital trackers and/or shale drilling.

ELEMENTS OF ANALYSIS

BACKGROUND

Since 1953, Section 4905.22 of the Ohio Revised Code (R.C.) has required utilities in Ohio to "furnish necessary and adequate service" and "provide such instrumentalities and facilities as are adequate and in all respects just and reasonable." In September 2011, R.C. 4929.111 permitted natural gas companies to apply to the Public Utilities Commission of Ohio (Commission) for approval of a capital expenditure program (CEP) for investment related to: infrastructure expansion, improvement, or replacement; programs to install, upgrade, or replace technology systems; or, programs to comply with government rules and regulations. With approval of a CEP, natural gas companies can establish a regulatory asset to defer for future recovery the post in-service carrying costs (capitalized interest or "PISCC") and depreciation and property tax expenses associated with the CEP assets.

In Case Nos. 11-5351-GA-UNC and 11-5352-GA-AAM, Columbia Gas Ohio, Inc. (Company or Columbia) sought and was granted authority to create a CEP and to begin deferring the related PISCC and depreciation and property tax expenses (the CEP Deferral) for capital investments that were not part of its accelerated infrastructure replacement program (IRP). The Commission authorized the CEP Deferral for the period October 1, 2011 through December 31, 2012 and determined that Columbia could only accrue the deferral up to the point where the deferred amount would exceed $1.50 per month for the Small General Service (SGS) class of customers if it were included in customer rates.

Subsequently, in Case Nos. 12-3221-GA-UNC and 12-3222-GA-AAM, the Commission authorized Columbia to continue the CEP Deferral beyond 2012, up to the point where the deferred amount would exceed $1.50 per month for the SGS class of customers if it were put into rates. The Commission also restated its determination that it would consider the prudence, reasonableness, and magnitude of the CEP Deferral and capital expenditures when Columbia applied for recovery.

On December 1, 2017, in Case No. 17-2202-GA-ALT, Columbia Gas of Ohio, Inc. (Columbia or Company) filed an application seeking authority from the Public Utilities Commission of Ohio (PUCO or Commission) for a new alternative rate plan to establish a capital expenditure program rider ("CEP Rider") on customer bills to collect the amounts accrued in the CEP Deferral through December 31, 2017. The Company filed an amended application on April 2, 2018. The Company stated that the purpose of the CEP Rider is to recover the post-in-service carrying costs, incremental depreciation expense, and property tax expense currently deferred pursuant to Columbia's capital expenditure program deferral ("CEP Deferral"), as well as the corresponding assets to which these expenses are directly attributable in the capital expenditure program.

The Public Utilities Commission of Ohio (Commission or PUCO) issued a request for proposal seeking proposals to conduct a two-part audit of Columbia's CEP capital expenditures. The first part of the audit is to review and attest to the accounting accuracy and used and useful nature of Columbia's non-IRP capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (December 31, 2007 as set in Case No. 08-072-GA-AIR, et al) through December 31, 2017. The second part of the audit is to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October

2011 through December 31, 2017.[2] Blue Ridge Consulting Services, Inc. (Blue Ridge) submitted a proposal and was selected to perform the review.

PURPOSE OF PROJECT

As defined in the RFP, the audit was to address two parts with the following scope:

Part 1 Plant In-Service Balances: Review and attest to the accounting accuracy and used and useful nature of Columbia's non-IRP capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (December 31, 2007 as set in Case No. 08-072-GA-AIR, et al) through December 31, 2017.

Part 2 Capital Expenditures Prudence Audit: Simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2017

PROJECT SCOPE

The project scope, as delineated in the RFP, addresses the following items:

Part 1 Plant In-Service Balances

- Determine total company plant in-service for each account and subaccount, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.
- Audit Columbia's plant in-service to determine the proper value for non-IRP investments by account and subaccount.
- Determine total company depreciation reserve for each account, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.
- Audit Columbia's depreciation reserve to determine the proper value for non-IRP investments by account and subaccount.
- Provide a determination as to the accuracy and completeness of Columbia's historical plant records and continuing property record.
- Ensure plant in-service transactions were properly classified as a capital expenditure.
- Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense.
- Perform physical inspections to confirm the assets used and usefulness.
- Provide a report of findings that include rationale and description of any recommended adjustments.

Part 2 Capital Expenditure Prudence Audit

- Identify and assess the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.
- Identify and assess the necessity, reasonableness, and prudence of Columbia's policies and practices for plant additions, new construction, plant replacement, and plant retirements.

[2] Case No. 17-2202-GA-ALT Request for Proposal No. RA18-CSPA-1, pages 1-2.

- Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in Columbia's non-IRP capital expenditures coinciding with the CEP program.
- Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of outside contractors for non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.
- Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of internal company labor for non-IRP capital expenditures and assets for the period January 1, 2008, through December 31, 2017, with an emphasis on CEP expenditures and assets.
- Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of any other Columbia capital spending policies and practices or lack of such practices not specifically identified herein.
- Recommend and support specific adjustments to the non-IRP plant in-service balance based on any findings of lack of necessity, unreasonableness, or imprudence.

Blue Ridge's analysis and recommendations did not include the following items:

- Verification of the accuracy of the Company's CEP deferral revenue requirement model calculations and the appropriateness of assumptions used (e.g. PISCC and property taxes)
- Disallowances based on prior Commission precedents or policy
- Review of the appropriateness of jurisdictional allocation factors
- Appropriateness and accuracy of Company overhead allocations applied to capital work orders
- Accumulated deferred income taxes including the potential impact of the Tax Cuts and Jobs Act of 1987 on the excess deferred income tax balances

AUDIT STANDARD

Blue Ridge's focus is on the accounting accuracy; used and useful nature; and the necessity, reasonableness and prudence of the non-IRP capital expenditures. Blue Ridge used the following standard during the course of the audit when assessing the attributes required in the project scope:

Accounting Accuracy: The stated value is supported by accurate and complete plant accounting property records. Transactions are properly recorded as capital expenditures in the appropriate FERC account.

Used and Useful: The assets are used in providing services and are useful to the ratepayer.

Necessity, Reasonableness, and Prudence: The decision to make the investment was reasonable at the time the decision was made and based on information then available. The decision is one that a reasonable person could have made in good faith, given the information and decision tools available at the time of the decision.

MATERIALITY

Materiality relates to the importance or significance of an amount, transaction, or discrepancy. The assessment of materiality depends on certain factors, such as an organization's revenues and expenses. For a regulated utility, the impact on a company's ratepayer should also be considered.

Under traditional cost-of-service ratemaking, revenue requirements, or cost of service, equates to the total of operating expenses, depreciation, taxes, and a rate-of-return allowance on the utility's investment in rate base. Blue Ridge used the traditional cost-of-service concept to identify materiality as it relates to changes in the plant-in-service component of rate base. Materiality was calculated by backtracking through the Company's revenue requirements calculation to determine the amount of change in gross plant in-service that would result in a 0.75 percent change in an average residential customers monthly bill (without fuel). Blue Ridge found that a $37,211,105 change in gross plant in-service would result in 0.75 percent change in an average residential customer's monthly bill (without fuel).[3]

The resultant materiality threshold was used to determine the *tolerable error* in the calculation of the sample size for detailed transactional testing. Blue Ridge's findings were not limited by the tolerable error. We reported on all our findings regardless of amount.

Information Reviewed

Blue Ridge reviewed the following information as required by the RFP:

- Applicable testimony and work papers Cases 11-5351-GA-UNC and 12-3221-GA-UNC, et al and Case No. 17-2202-GA-ALT
- Generally accepted accounting principles (GAAP)
- Federal Energy Regulatory Commission (FERC) Uniform System of Accounts
- Various accounting and tax changes or decisions issued during calendar year 2017
- The operations and regulatory environment of natural gas distribution utilities
- The capital spending practices and requirements of natural gas distribution utilities
- The Pipeline and Hazardous Materials Safety Administration's (PHMSA) Pipeline Safety Regulations (49 CFR, Parts 190-199)

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

Interviews and Field Observations

Blue Ridge conducted interviews of Company personnel and performed field inspections and desk top reviews.

The interview notes are included within the electronic appendices to this report. Blue Ridge's interviews focused on the following areas:

1. Plant Accounting
2. Major Events from January 1, 2008 through December 31, 2017, that could have had an impact on Plant Accounting records
3. Engineering
4. Work Order Development
5. Information Technology
6. Capital Budgeting

[3] WP-17-2202-GA-ALT Sensitivity and Sample Size. The calculation used the Company's CEP Revenue Requirement model and assumes no other adjustments were made to the Company's revenue-requirement calculation.

The objectives of the field inspections focused on (1) Used and Usefulness: whether the Company assets were used and useful, providing service to the customer, and, therefore, properly included in utility plant in service. (2) Necessity, Reasonableness, and Prudence: whether the decision to make the investment was reasonable at the time the decision was made and based on information then available. The field inspections included on-site visits to review the overall construction at each site to determine whether the assets appeared to be in use and, therefore, used and useful. The review also determined whether the assets appeared overbuilt (gold plated) and whether the Company selected a reasonable option to execute the work. The reviews included inspection of drawings, schematics, notes, and other documentation that supported the reasonableness of the decision to execute the work. Where on-site visits were not practical, as in the case of work that could not be seen, a desk-top review was conducted to examine the supporting documentation for the work performed.

Additional discussion on the team's observations are included in the section labeled Physical Inspections and Desktop Reviews. The field observation notes and photos are included within the electronic appendices to this report.

PROJECT REQUIREMENTS AND RELATED SUMMARY CONCLUSIONS

The Request for Proposal (RFP) included general project requirements for the auditor investigation that were separated into two parts: (1) Plant In-Service Balances and (2) Capital Expenditures Prudence. The two parts are interrelated and the findings in each part are used to support Blue Ridge's ultimate recommendations. To ensure that we have addressed the specific requirements in the RFP, we have maintained the integrity of the work scope by part. The following lists include the subject areas of the RFP's required audit components and how this section of the report is organized.

Part 1 Plant In-Service Balances

The RFP stated that the purpose for the first part of the audit was to "review and attest to the accounting accuracy and used and useful nature of Columbia's non-IRP capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (December 31, 2007 as set in Case No. 08-072-GA-AIR, et al) through December 31, 2017." Specific scope included the following items:

1. Plant in Service Schedules
    - Determine total company plant in-service for each account and subaccount, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.
    - Audit Columbia's plant in-service to determine the proper value for non-IRP investments by account and subaccount.
2. Depreciation Reserve
    - Determine total company depreciation reserve for each account, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.
    - Audit Columbia's depreciation reserve to determine the proper value for non-IRP investments by account and subaccount.
3. Historical Records
    - Provide a determination as to the accuracy and completeness of Columbia's historical plant records and continuing property record.
4. Classification—Capital vs. Expense
    - Ensure plant in-service transactions were properly classified as a capital expenditure.
5. Subaccounts—Allocations and Depreciation
    - Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense.
6. Physical Inspections
    - Perform physical inspections to confirm the assets used and usefulness.

Part 2 Capital Expenditures Prudence Audit

For the second part of the audit, the RFP stated the purpose as "to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2017." Specific scope included the following items:

7. Necessity, Reasonableness, and Prudence
    - Identify and assess the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.
8. Policies and Practices
    - Identify and assess the necessity, reasonableness, and prudence of Columbia's policies and practices for plant additions, new construction, plant replacement, and plant retirements.
    - Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of any other Columbia capital spending policies and practices or lack of such practices not specifically identified herein.
9. Causes for Increased Non-IRP Spending
    - Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in Columbia's non-IRP capital expenditures coinciding with the CEP program.
10. Cost Containment
    - Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of outside contractors for non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.
    - Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of internal company labor for non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.
11. Recommended Adjustments
    - Recommend and support specific adjustments to the non-IRP plant in-service balance based on any findings of lack of necessity, unreasonableness, or imprudence.

The following subsections address the RFP requirements delineated above and Blue Ridge's summary conclusions based on our analysis. Additional information related to the analysis is provided in the next section of this report: Detailed Analysis, Findings, and Recommendations.

1. PLANT-IN-SERVICE SCHEDULES

Requirements: Determine total company plant in-service for each account and subaccount, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.

Requirement: Audit Columbia's plant in-service to determine the proper value for non-IRP investments by account and subaccount.

The Company's last base rate case (Case No. 08-0072-GA-AIR) included plant in-service schedules (B Schedules) as of December 31, 2007. While the Company has not filed an application to increase its general rates, it supplied Blue Ridge with plant in-service schedules as of December 31, 2017. The information provided also included roll forward balances from 2008 through 2017.[4]

Blue Ridge investigated the information provided on the plant-in-service schedules to confirm the reasonableness of the balances. These schedules included the Company's plant in service by major property groupings (Schedule B-2), plant in service by accounts and subaccounts (Schedule B-2.1), and gross additions, retirements, and transfers (Schedule B-2.3).

Blue Ridge found that the other plant schedules were not relevant to this investigation for the following reasons: Schedule B-2.2, adjustments to plant in service—the balances provided reflect Columbia's books as of the date certain with no adjustment to plant in service; Schedule B-2.4, lease property—Columbia accounts for all leased property as operating leases and does not include lease property in plant in service; and Schedule B-2.5, property excluded from rate base—all adjustments are detailed on Schedules B-2.1 and B-2.2.

Blue Ridge's investigation included data requests, interviews, field inspections, and analyses, including, among other analyses, variance analysis, and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service schedules. These adjustments are addressed throughout the report and are summarized in the Executive Summary, along with the result of Blue Ridge's recommended adjustments on net plant.

Blue Ridge's recommended adjustments have been included in the recast plant-in-service schedules that are provided in Appendix D.

2. DEPRECIATION RESERVE

Requirement: Determine total company depreciation reserve for each account, from the date certain balance approved in Columbia's previous application to increase rates forward through December 31, 2017.

Requirement: Audit Columbia's depreciation reserve to determine the proper value for non-IRP investments by account and subaccount.

The Company's last base rate case (Case No. 08-0072-GA-AIR) included depreciation reserve schedules (B Schedules) as of December 31, 2007. While the Company has not filed an application to increase its general rates, it supplied Blue Ridge with depreciation reserve schedules as of December 31, 2017. The information provided also included roll forward balances from 2008 through 2017.[5]

[4] Columbia response to Blue Ridge Data Request Set 1-6.
[5] Columbia response to Blue Ridge Data Request Set 1-6.

Blue Ridge investigated the information provided on the depreciation reserve schedules to confirm the reasonableness of the balances. These schedules included Columbia's reserve for accumulated depreciation by major property groupings (Schedule B-3), jurisdictional reserve balances by accounts (Schedule B-3.2), depreciation reserve accruals, retirements, and transfers (Schedule B-3.3).

Blue Ridge found that the other depreciation reserve schedules were not relevant to this investigation for the following reasons: Schedule B-3.1, adjustments to the reserve for accumulated depreciation—Columbia has not made any adjustments to the Reserve for Accumulated Depreciation and Amortization; and Schedule B-3.4, depreciation reserve and expense for lease property—depreciation is not accrued on leased property.

Blue Ridge found that the CEP Deferral depreciation reserve reflects the cumulative depreciation expense since the CEP inception as calculated using a composite depreciation rate. The reserve was not provided on a FERC account basis and is not based on the balances within the Company's books and records. The Company agreed to work with Staff to provide non-IRP gross plant and reserve balances by FERC account.

Blue Ridge's investigation included data requests, interviews, field inspections, and analyses, including, among other analyses, variance analysis, and detailed transactional testing. Blue Ridge's investigation identified three recommended adjustments that should be applied to the plant-in-service schedules and their associated depreciation reserve balances. These adjustments are addressed throughout the report and are summarized in the Executive Summary, along with the result of Blue Ridge's recommended adjustments on net plant.

Blue Ridge's recommended adjustments have been included in the recast plant-in-service schedules that are provided in Appendix D.

3. Historical Records

Requirement: Provide a determination as to the accuracy and completeness of Columbia's historical plant records and continuing property record.

Through our analysis, Blue Ridge found that the Company was able to provide detailed continuing property records to support its plant in service balances.

For the work order / projects detail that the Company provided, Blue Ridge performed detailed transactional testing. The results of this analysis are discussed in this report's Detailed Transactional Testing subsection.

4. Classification—Capital vs. Expense

Requirement: Ensure plant in-service transactions were properly classified as a capital expenditure.

Through our transactional detail testing (Step T3), Blue Ridge found that all the work included in the projects sampled are capital in nature, and the scope of work and cost detail coincided with the applicable FERC 300 accounts to which the work applies in accordance with the FERC Uniform System of Accounts (CFR 18). The projects were classified to the proper intangible, distribution, and general equipment FERC accounts.

5. SUBACCOUNTS—ALLOCATIONS AND DEPRECIATION

Requirement: Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense

Schedule B-3.2 Depreciation Accrual Rates and Jurisdictional Reserve Balances by Accounts provides the intangible, distribution, and general plant at the summary FERC 300 account level of the jurisdictional net plant in service. The depreciation schedule is tied to Schedule B-2.1 and provides the summary FERC 300 accounts with total Company amounts and the allocators used to derive the adjusted jurisdictional balances. The Company provided a list of subaccounts that have been added since the Commission approved depreciation rates in Case No. 08-72-GA-AIR. The Company also provided the depreciation rates in use for those accounts and stated that the computation of depreciation expense for these subaccounts reflects applicable most recent Commission-approved depreciation rates.[6] This list of new accounts is summarized below by summary FERC 300 account. The complete list of new subaccounts is available in the workpapers in Appendix C.

Table 1: Additional Subaccounts Added Since Depreciation Rates Were Approved[7]

Mapped Account	Account Title	Additional Subaccounts
	Intangible	
30100	Organization	1
30200	Franchise and Consents	1
30300	Miscellaneous Intangible Plant	8
	Distribution	
374.00	Land and Land Rights	7
375.34	Structures and Improvement - Meas. & Reg.	7
375.56	Structures and Improvement - Ind. Meas. & Reg.	2
375.70	Structures and Improvement - Other Dist. System	5
376.00	Mains	5
378.00	Meas. And Reg. Sta. Equip.-General	9
379.00	Meas. And Reg. Sta. Equip.-City Ga	5
380.00	Services	10
381.00	Meters	7
382.00	Meter Installations	3
383.00	House Regulators	4
384.00	House Regulator Installations	1
385.00	Industrial Meas. And Reg. Sta. Equip.	3
387.00	Other Equip.	15
	General	
39000	Structures and Improvement	1
39100	Office Furniture and Equipment	6
39200	Transportation Equipment	2
39300	Stores Equipment	1
39400	Tools, Shop, and Garage Equipment	6
39500	Laboratory Equipment	1
39600	Power Operated Equipment	1
39800	Miscellaneous Equipment	1
	Leasehold	56
	Not Utilized	5
	Total Additional Subaccounts	173

[6] Columbia response to Blue Ridge Data Request 6-007.
[7] WP 17-2202-GA-ALT BRCS DR Set 6-7 Attachment A-Subaccounts.

The depreciation rates in use were approved by the Commission in Case No. 08-72-GA-AIR over ten years ago. Blue Ridge recommends that a depreciation study be performed, reflecting the numerous subaccounts that have been added since the last case, and rates be updated.

Depreciation Accrual Rates

The Company stated that depreciation accrual rates have not been changed since the Commission's approval in Case No. 08-0072-GA-AIR.[8] The Company provided a list of the most recent Commission-approved depreciation rates.[9] Blue Ridge compared the provided approved depreciation rates to those included on Schedule B-3.2 and found that the following FERC Accounts did not reflect the approved depreciation accrual rates. These accounts have sub accounts that are not reflected on Schedule B-3.2.

Table 2: Differences Between Depreciation Rates on Schedule B-3.2 and Approved by Commission[10]

		Depreciation Accural Rate	
Account No.	**Account Title**	**B-3.2**	**Approved**
37500	Structures and Improvement	2.71%	
375.34	Structures and Improvement - Meas. & Reg.		2.73%
375.56	Structures and Improvement - Ind. Meas. & Reg.		3.75%
375.70	Structures and Improvement - Other Dist. System		2.71%
375.70	Structures and Improvement - Communications Structures		2.00%
38100	Meters	4.24%	
381.00	Meters		2.28%
381.00	Automatic Meter Reading Devices		6.67%
38700	Other Equip.	4.55%	
387.00	Other Equip.		5.83%
387.00	Other Equip. - Customer Information Services		4.55%
39100	Office Furniture and Equipment	10.09%	
39100	Office Furniture and Equipment		5.00%
39100	Office Furniture and Equipment - Info. Sys.		20.00%
39400	Tools, Shop, and Garage Equipment	4.91%	
39400	Tools, Shop, and Garage Equipment		4.00%
39400	CNG Equipment		10.00%

The Company explained that depreciation accrual rates included in Schedule B-3.2 are calculated average depreciation rates for the FERC account. The Commission-approved rates are utilized at the sub-FERC account level, which arrives at the calculated average rate for the FERC account.[11] The Company's explanation is not unreasonable.

Composite Depreciation Rates

To calculate depreciation expense in the CEP deferral, the Company uses a composite depreciation rate. The Company provided the calculations of the composite depreciation rates since the inception of the CEP deferral. The rate was modified several times since 2011. The 2011 rate was calculated using the total of all FERC 300 plant accounts. Thereafter, the rate was computed based on the average total company composite rate adjusted for the impact of NIFIT and arena additions.[12]

[8] Columbia response to Blue Ridge Data Request 1-021.
[9] Columbia response to Blue Ridge Data Request 6-005.
[10] WP 17-2202-GA-ALT Set 1 No 6 Depreciation Rate Verification.
[11] Columbia response to Blue Ridge Data Request 17-001.
[12] Columbia response to Blue Ridge Data Request 6-004.

Blue Ridge compared the calculated composite rate to the rate used in the Annual Information filings and found several inconsistencies. As shown in the following table comparing the calculated rate to the rate used in the CEP Deferral, the Company used a rate that was not effective until August 2013 in its depreciation expense calculation in the earlier period of January 2011–December 2012. Also, the calculated rate that was effective October 2014 was not applied until November 2014.

Table 3: Comparison of Calculated Composite Deprecation Rate to Rate used in CEP Deferral[13]

Effective Date	Calculated Rate	Description
Beginning 10/2011	2.70%	
Beginning 8/2013	2.72%	Composite depreciation rate for assets in-service through February, 2014
Beginning 3/2014	3.50%	Forecasted depreciation rate as of March, 2014
Beginning 10/2014	3.64%	Forecasted depreciation rate as of October, 2014
Beginning 3/2015	3.53%	Forecasted depreciation rate as of March, 2015
Beginning 2019	3.53%	Forecasted depreciation rate
CEP Deferral Period	**Rate Used**	**Comment**
October 2011–December 2012	2.72%	Used Rate that was not effective until August 2013
January 2013–July 2013	2.70%	
August 2013–February 2014	2.72%	
March 2014–October 2014	3.50%	
November 2014–February 2015	3.64%	Rate should have started October 2014
March 2015–December 2018	3.53%	

The inconsistent use of the calculated composite depreciation rate results in a misstatement of the CEP depreciation expense and the resultant accumulated depreciation. Blue Ridge recommends that the Company work with Staff to review the depreciation expense and the resultant accumulated depreciation calculation and incorporate any necessary adjustment. The composite rate has no effect on the roll-forward balances, as those are related on FERC-account-specific depreciation accrual rates.

Allocation Factors

Allocation factors are not used to allocate distribution plant. The Company stated 100 percent of Columbia's investment is jurisdictional and used and useful to provide gas service to its customers.[14]

6. Physical Inspections

Requirement: Perform physical inspections to confirm the assets used and usefulness.

Blue Ridge concludes the physical inspections determined that the assets were used and useful and provide benefit to the ratepayer. The assets did not appear over built. Company personnel appeared knowledgeable about the projects.

[13] WP 17-2202-GA-ALT BRCS DR Set 1-007 Attachment A Annual Info Filings.
[14] Columbia response to Blue Ridge Data Request 1-023.

Desktop reviews performed determined that the Company had adequate supporting documentation for the projects, including the appropriate Engineering detail. The projects appeared to have been adequately planned with alternatives vetted. As a result, the projects are used and useful and providing benefit to the ratepayers.

We did not find anything in either the physical inspections or desktop reviews that is not unreasonable.

Additional details of the field reviews are included in this report's Field Inspections and Desktop Review subsection. The inspection forms and photos are included in Appendix C.

7. Necessity, Reasonableness, and Prudence

Requirement: Identify and assess the necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.

Other than three recommended adjustments associated with cost overruns for which the Company was unable to provide documentation fully explaining the overrun, Blue Ridge found nothing to indicate that the non-IRP capital expenses and assets for the period January 1, 2008, through December 31, 2017, were unnecessary, unreasonable, or imprudent. The necessity, reasonableness, and prudence of Columbia's non-IRP capital expenditures was considered throughout the entire audit, including the variance analysis, transactional testing, and physical inspections and desktop reviews. Our work in that regard is discussed in various sections of this report.

8. Policies and Practices

Requirement: Identify and assess the necessity, reasonableness, and prudence of Columbia's policies and practices for plant additions, new construction, plant replacement, and plant retirements.

Requirement: Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of any other Columbia capital spending policies and practices or lack of such practices not specifically identified herein.

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as not to adversely affect the balances in distribution utility net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. Blue Ridge also reviewed internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits. In addition to a review of the Company's formal policies and procedures, Blue Ridge conducted interviews with a focus on understanding the processes and any changes that have been made since 2008.

A few significant events occurred during the scope period of this audit. Most were in regard to software (PeopleSoft and PowerPlant) implementation and/or upgrades. Another significant event, the NiSource separation into two distinct energy infrastructure companies: a fully regulated natural gas and electric utilities company (NiSource) and a natural gas pipeline, midstream, and storage company (Columbia Pipeline Group) in 2015, had no resultant impact on Columbia's plant balances.

At the time of the 2015 NiSource separation, Columbia's capitalization policy was reviewed and consolidated with all other local distribution companies at NiSource to form a NiSource-wide Plant Capitalization Policy. No major changes were made to Columbia's application of the policy as a result of this review and consolidation activity. There were, however, changes related to the Software Capitalization Policy in order to create one consistent threshold for utilization across all NiSource companies.

Blue Ridge concluded that Columbia's controls were adequate and not unreasonable. Furthermore, we were satisfied with actions taken with regard to internal and other audits reviewed.

Additional details of the policies and practices reviews are included in this report's Review of Company's Processes and Controls subsection.

9. Causes for Increased Non-IRP Spending

Requirement: Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in Columbia's non-IRP capital expenditures coinciding with the CEP program.

Capital spending has increased significantly since the inception of the CEP. The Company identified pressures on its capital budgets due to a constrained labor market and increased restoration requirements and permitting fees for local and state government, as well as an increase in the volume of required relocation work.[15] There also have been large Shared Services projects, such as the new Arena headquarters in 2014 and the information technology system upgrades in 2017. However, Growth-related activities is the largest annual spend category.

Starting in 2012 (the first full year of the CEP), the actual spend on growth increased 64%. That trend continues through 2017 with a combined 149% increase from 2012 through 2017. Certain areas of the Company service territory have seen steady growth, which would contribute to the need for more spending. Growth-related activities are driven, as expected, by service and main pipe-related activities. Labor costs are the major contributor to the CEP costs. Contractor costs have affected the annual cost per total mile of main.

Additional details of the Company's capital spending are included in this report's Capital Spending and Cost Containment subsection.

10. Cost Containment

Requirement: Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of outside contractors for non-IRP capital expenditures and assets for the period January 1, 2008 through December 31, 2017, with an emphasis on CEP expenditures and assets.

Requirement: Identify and assess the reasonableness and prudence of Columbia's cost containment strategies and practices in the use of internal company labor for non-IRP capital expenditures and assets for the period January 1, 2008 through December 31,2017, with an emphasis on CEP expenditures and assets.

The CEP costs are increasing. Part of the reason is the extent of work going on, and part of it has to do with rising contractor costs. Labor costs are a significant driver of the increasing costs of the non-IRP projects. The demand for qualified crews is increasing while the supply is decreasing.

[15] Columbia Gas response to Blue Ridge Data Request 3-008.

Contractor constraints are expected to continue in the foreseeable future. The Company understands the key labor cost drivers and provided steps it is taking to control those costs. The actions taken by Columbia are discussed in detail in the section identified as Cost Containment. Blue Ridge concludes that the Company is implementing sound cost containment strategies. But although those strategies may be slowing the impact, they are not negating the fact that the Ohio pipe construction market is a constrained market, as are also the neighboring states which also have accelerated capital trackers and/or shale drilling.

11. Recommended Adjustments

Requirement: Recommend and support specific adjustments to the non-IRP plant in-service balance based on any findings of lack of necessity, unreasonableness, or imprudence.

Blue Ridge's recommends the following adjustments:

- Work Order 0555.34120122190—Instl 1680'-6"P-Ip-Betterment: Snow: Par $285,979. Original budget was $236,402. Therefore, the project was over budget by $49,577. Columbia was unable to locate the policy required Level 1 variance explanation for this work order and was unable to provide a explanation for the variance. Blue Ridge recommends the cost overrun be disallowed from the CEP [**ADJUSTMENT #1**].
- Work Order 0561.34160139991—Public Improvement, $701,219. This work order was over budget by more than 20%. The project estimate was $578,717 and the cost overrun was $122,502. The Company provided a variance report which explained that additional asphalt was required, additional flagger hours were required and 50 additional hours of sewer camera. The Company explained what was over budget but not what caused it. Therefore, Blue Ridge recommends that the CEP be reduced by the overrun since they could not explain the reasons behind the overrun. [**ADJUSTMENT #2**]
- Work Order 0565.34130062345—4"Sl - London Correctional: London Cor: $46,192 The original budget was $12,561. Therefore, the project was over budget by $33,631. Columbia was unable to locate the policy required Level 1 variance explanation for this work order and was unable to provide an explanation for the variance. Blue Ridge recommends the cost overrun be disallowed from the CEP [**ADJUSTMENT #3**]

DETAILED ANALYSIS, FINDINGS, AND RECOMMENDATIONS

Blue Ridge's review was focused on whether Columbia has accurately accounted for its plant in service and depreciation reserve as of December 31, 2017, and whether those investments were used and useful, necessary, reasonable, and prudent. Our investigation covered all capital assets from its most recent base rate case (December 31, 2007 as set in Case No. 08-072-GA-AIR, et al) through December 31, 2017, with a focus on CEP expenditures from October 2011 through December 31, 2017.

The following sections discuss Blue Ridge's review of the Company's processes and controls, variance analysis, and detailed transactional testing. We have also included summary of our findings and our recommendations.

REVIEW OF COMPANY'S PROCESSES AND CONTROLS

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as not to adversely affect the balances in distribution utility net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. Blue Ridge also reviewed internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits. In addition to a review of the Company's formal policies and procedures, Blue Ridge conducted interviews with a focus on understanding the processes and any changes that have been made since 2008.

SUMMARY OF POLICIES AND PROCEDURES

The audit of the Columbia's plant-in-service balances 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 the Company's processes and controls to obtain an understanding of their impact on the plant balances. In particular, Blue Ridge reviewed the following policies and procedures:

1. Plant Accounting:
    a. Capitalization vs Expense
    b. Preparation and approval of work orders
    c. Recording of CWIP, including the systems that feed the CWIP trial balance
    d. Application of AFUDC
    e. Recording and closing of additions, retirements, cost of removal and salvage to plant
    f. Unitization process based on the retirement unit catalog
    g. Application of depreciation
    h. Contributions in Aid of Construction (CIAC)
    i. Damage Claims
2. Purchasing/Procurement
3. Accounts Payable/Disbursements
4. Accounting/Journal Entries
5. Payroll (direct charged and allocated)
6. Insurance recovery
7. Allocations
8. Work Management System

9. Information Technology
10. Capital Project selection and prioritization
11. System planning and load growth

Current Policies and Procedures

Blue Ridge reviewed current policies and procedures in the areas that provide input into distribution plant, including capitalization, purchasing and procurement, accounts payable and disbursements, accounting and journal entries, payroll, insurance recovery, allocations, work management system, and information technology.[16] We also reviewed the Company's formal and informal processes for work orders and approvals, damage claims, accounting and journal entries, and allocations. Blue Ridge ensured its understanding of the policies and procedures through interviews.

The Company also maintains a Unit of Property Catalog that encompasses all its regulated distribution assets.[17] Modifications to the catalog are infrequent and typically would occur to address process/material changes not addressed by the existing list of capital assets or to address a circumstance not previously identified.[18]

Blue Ridge found that the Company's current policies and procedures are not unreasonable.

Changes to Capitalization Policy

The Company reviews its capitalization policies annually to determine whether changes are necessary. If a change is necessary, the modification will be vetted at the management level, including consideration and approval by the Chief Accounting Officer.[19]

In 2015, Columbia's capitalization policy was reviewed and consolidated with all other local distribution companies at NiSource to form a NiSource-wide Plant Capitalization Policy. No major changes were made to Columbia's application of the policy as a result of this review and consolidation activity. There were, however, changes related to the Software Capitalization Policy were implemented in order to create one consistent threshold for utilization across all NiSource companies.[20]

Significant Events Between October 1, 2008, and December 31, 2018

The Company has undergone several events that could affect its asset recording and tracking:[21]

1. In 2012, Columbia upgraded its PowerPlant system software to version 10.3.3. The upgraded version enabled installation of Provision and Property Tax modules. Based on PowerPlant's SOX 404 system status, the system underwent IT General Controls testing.
2. NiSource launched a project to adopt a common financial system (PeopleSoft) and processes that permitted the use of a common general ledger and chart of accounts for all NiSource companies, which was placed in-service in 2014. The project focused on the replacement of

[16] Columbia Gas response to Blue Ridge Data Request 1-014.
[17] Columbia Gas response to Blue Ridge Data Request 1-018.
[18] Interview with Plant Accounting on June 22, 2018, and Columbia's response to Blue Ridge Data Request 7-002.
[19] Interview with Plant Accounting on June 22, 2018.
[20] Columbia Gas response to Blue Ridge Data Request 1-017.
[21] Columbia Gas response to Blue Ridge Data Request 1-013.

four separate general ledger software packages, three of which were no longer supported by their respective vendors, including the financial software package used by Columbia. The general ledger and accounts payable system used by Columbia at the time of the initiative was GEAC. That software has become obsolete (no longer offered for sale or supported). Over the years, Columbia had customized GEAC to address specific needs, and as a result of its age and customization level, IT resources required to support GEAC became increasingly difficult to obtain. NiSource employed a six-step conversion process to ensure integrity of data. Conversion steps included Data Clean-Up, Extraction, Load to Staging, Translation/Transformation, Load, and Reconciliation. Other than the investment in the new system, plant balances in PowerPlant were not impacted. Some reconfiguration in PowerPlant was required to interface with the new general ledger. Reconciliations were performed to ensure plant balances fed to general ledger agreed to the source system. Upgrades to PeopleSoft and PowerPlant are tested under IT General Controls testing.

3. In 2015, NiSource separated into two distinct energy infrastructure companies: a fully regulated natural gas and electric utilities company (NiSource) and a natural gas pipeline, midstream, and storage company (Columbia Pipeline Group). There were no impacts on Columbia's plant balances as a result of the separation.
4. In 2018, Columbia began (and is currently in) the process of upgrading to PowerPlant 2017.2. The upgraded version is currently expected to be effective August 2018. The upgrade is primarily as a result of the new lease accounting guidance.

REVIEW OF OTHER AUDITS

Blue Ridge requested and reviewed a list of the audits performed by the internal audit group during the period October 1, 2008, through December 31, 2017,[22] and selected several to examine further regarding potential findings that could have had an impact on the internal controls of the feeder systems that charge distribution work orders or feed CWIP, including those affecting payroll, Materials and Supplies, transportation, overheads, and contractors. Based upon our review, the audit conclusions either did not pertain or did not engender a level of concern that the Company's controls were less than adequate.[23]

Blue Ridge reviewed the SOX compliance audits that feed CWIP performed and found that control issues were minor and did not amount to items of financial significance.[24]

Blue Ridge also reviewed the only FERC Audit associated with Columbia Gas, which was an audit of NiSource Inc. conducted in 2012. The audit covered (1) cross-subsidization restrictions on affiliate transactions, (2) accounting, recordkeeping, and reporting requirements, (3) Uniform System of Accounts for centralized service companies, (4) preservation of records requirements for holding companies and service companies, (5) FERC Form No. 60 Annual Report requirements, and (6) accounting requirements for transactions with associated companies as well as compliance with the applicable reporting requirements for public utility and natural gas companies. The audit period covered calendar years 2009 and 2010.[25] The audit staff found eight areas of noncompliance;

[22] Columbia Gas response to Blue Ridge Data Request 1-025.
[23] Columbia Gas response to Blue Ridge Data Requests 2-4, Attachment a, and 3-9.
[24] Columbia Gas response to Blue Ridge Data Request 1-026.
[25] Columbia Gas response to Blue Ridge Data Request 1-024.

however, the areas involved were either not associated with Columbia Gas or did not lead Blue Ridge to the conclusion that the accuracy of Columbia Gas plant balances were compromised.

Blue Ridge concluded that Columbia's controls were adequate and not unreasonable. Furthermore, we were satisfied with actions taken with regard to internal and other audits reviewed.

VARIANCE ANALYSIS

Blue Ridge's variance analysis focused on two areas. The first was to compare distribution (FERC accounts 360 through 374), general (FERC accounts 390 through 399), and intangible (FERC account 303) plant balances for each scope year (2008 through 2017) to the annual reports filed with the Commission to identify and reconcile any differences. We prepared a spreadsheet table of for each account and year, calculated the differences, and requested from the Company explanations for those differences. Of the 216 account and year combinations, the majority (131) matched. Blue Ridge requested the Company to provide reconciliation for the 85 variances. As explained by the Company, reconciliation was achieved, eliminating most of the variances by recognizing amounts from accounts 106 and 114 in the plant balances which were not in the Annual Report listings (which included only account 101). The other few variances were due to failures to properly assign certain additions, retirements, and transfers to the applicable FERC accounts.[26] However, the failures of proper account assignment had no impact on the overall cumulative balance for each of the calendars. Therefore, Blue Ridge was satisfied with the account comparison.

The second area of focus for variance analysis concerned identifying, quantifying, and explaining significant net plant changes, transfers, and adjustments within the individual distribution, general, and intangible plant accounts for each year from 2008 through 2017. Blue Ridge took note of anomalous or undefined changes in balances and asked the Company for explanations. Based on its investigative and analytical evaluation of the causes and details included in the Company's explanations, Blue Ridge attempted to determine the reasonableness of those changes.

Blue Ridge submitted 119 examples of questions and anomalies to the Company for explanation. The submitted items included such questions as detail behind transfers and reclassifications, retirement amounts greater than additions, significant additions over previous trend, significant retirements over previous trend, negative additions, and positive retirements. The Company responded with explanations for each instance,[27] and after some follow-up discussion,[28] Blue Ridge was satisfied that the activity was not unreasonable.

DETAILED TRANSACTIONAL TESTING

The Company provided a list of 15,494 work orders / projects that support gross plant in service from January 1, 2008, through December 31, 2017. The list was compiled of 7,884 CEP-related work orders and 8,767 non-CEP-related work orders.[29] These work orders / projects included $2,555,079,099 in assets. Blue Ridge reconciled the list of work orders to the Company's Annual Informational Reports and Plant In-Service Schedules to ensure that the work order population was complete. From this population, Blue Ridge selected specific work orders/projects for detailed transactional testing.

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[26] Columbia Gas response to Blue Ridge Data Request 5-001, including Attachment 1.
[27] Columbia Gas response to Blue Ridge Data Request 6-003, Attachment 1.
[28] Columbia Gas response to Blue Ridge Data Requests 12-001 and 15-001.
[29] Columbia Gas response to Blue Ridge Data Request 1-009 Attachment A Revised.

In addition, the Company provided a list of major additions or replacements from January 1, 2011, through December 31, 2017,[30] that included major main replacement,[31] M&R (Meter and Regulator) projects with a cost greater than $500,000, and other major additions. Blue Ridge considered this information when selecting projects for transactional testing.

Blue Ridge performed the following review steps.

1. Developed an understanding of CEP and non-CEP projects

   Blue Ridge developed an understanding of the difference between CEP and non-CEP projects. To understand what was included in CEP, the Company explained that CEP projects cover Columbia's investments that are not part of Columbia's IRP.

   <u>IRP Project Identification</u>

   To understand what is included in CEP, it was helpful to understand the Company's IRP projects. Columbia's IRP consists of three capital components:[32]

   1. Accelerated main replacement program (AMRP)—replacement of cast iron, wrought iron, unprotected coated steel, and bare steel pipe and metallic service lines.

      Columbia includes within its IRP program a mechanism for recovering costs associated with the accelerated replacement of priority pipe and the associated metallic customer- or Company-owned service lines. Priority pipe is defined as pipe which includes all Columbia's cast iron pipe, wrought iron pipe, bare steel pipe, unprotected coated steel pipe, and the associated metallic customer- or Company-owned service lines. Columbia may include, as part of the AMRP, interspersed sections of non-priority pipe, including first generation plastic pipe known as Aldyl-A, within certain specified limits, as a part of priority pipe replacement projects, when it is more economical to replace such non-priority pipe rather than attempt to tie into the existing sections of pipe. In addition, where Columbia replaces a segment of pipe or a service line which is replaced as part of the AMRP, Columbia may capitalize and recover the costs of moving an inside meter to an outside location, subject to certain conditions.

   2. Hazardous customer service lines (HCSL)—replacement of potentially hazardous customer owned service lines and prone-to-failure risers.

      As part of the IRP, Columbia capitalizes the costs associated with maintaining, repairing, and replacing customer service lines that Columbia has determined present an existing or probable hazard to persons or property.

   3. Automated meter reading devices (AMRD)

      Columbia also includes within Rider IRP the costs associated with installing automatic meter reading devices on all residential and commercial meters. Columbia has completed the installation of AMRDs. However, the AMRD component will remain in Rider IRP until Columbia includes its pre-2014 AMRD-related investments into its base rates during its next base rate case.[33]

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[30] Columbia Gas response to Blue Ridge Data Request 1-012.
[31] Pipe size greater than 8 inches and at least 50 feet.
[32] Columbia Gas response to Blue Ridge Data Request 1-001.
[33] Columbia Gas response to Blue Ridge Data Request 1-001

CEP Project Identification

Projects that do not meet the IRP criteria are removed from the IRP program and categorized as various types of CEP projects (i.e., Replacement / Public Improvement / Betterment; Acquisition; Growth; Support Services; Information Technology; and Distribution Integrity Management Plant Implementation).[34]

2. Reconciliation of Work Order / Annual Informational Reports and Plant In-Service Schedules

To ensure that Blue Ridge was provided a comprehensive list of work orders / projects for review and testing, we compared the lists of work orders / projects ("work order population")[35] to the totals in the annual report of utility plant in service filed with the Commission.[36] With the help of the Company, Blue Ridge was able to reconcile the total additions in the work order population for CEP and non-CEP additions to the 2008 through 2017 annual reports.[37]

3. Determining Work Order Sample

Blue Ridge selected 189 CEP and NON-CEP work orders / projects reflecting thousands of cost line items using the probability-proportional-to-size (PPS) sampling technique and professional judgement. The work orders selected based on professional judgment focused on individual (rather than blanket) work orders that have a high-dollar value and occurred from October 2011 through December 2017.

[34] Columbia Gas response to Blue Ridge Data Request 1-001
[35] Columbia Gas response to Blue Ridge Data Request 1-009 Attachment A.
[36] Columbia Gas Supplemental response to Blue Ridge Data Request 1-010 Attachment A and WP 17-2202-GA-ALT Sensitivity and Sample Size Sent to Staff 06-07-18 – Intervals (Tab: Reconciliation).
[37] Columbia Gas Supplemental response to Blue Ridge Data Request 1-010 Attachment A and an email from Diana Beil Subject: Re_ Columbia Gas PIS_CEP Audit - Reconciliation Question (dated 6/5/18).

Table 4: Sample Selected for Further Review and Testing

	CEP[38]	**Non-CEP**[39]
Reconciled Work Order Population[40]	7,884	8,768
Line Items in Population[41]	77,769	191,606
Dollar Amount in Population[42]	$660,093,110	$1,894,985,989
Specific Projects		
Workorders selected with Statistical Sampling	46	54
Dollar amount selected with Statistical Sampling	$102,021,187	$80,783,891
Workorders selected based on Judgement	10	2
Dollar amount selected based on Judgement	$6,973,236	$2,262,108
Workorders *within Specific Projects Sample*	**56**	**56**
Dollar Amount within Specific Projects Sample	**$108,994,423**	**$83,045,999**
Blanket Work Orders		
Workorders selected with PPS Sampling Technique	31	42
Dollar Amount selected with PPS Sampling Technique	$138,947,300	$614,747,209
Workorders selected based on Judgement	3	1
Dollar Amount selected based on Judgement	$9,627,210	$4,070,617
Workorders within Blanket Work Order Sample	**34**	**43**
Dollar Amount within Blanket Work Order Sample	**$148,575,510**	**$618,817,826**
Total Line Items Chosen for Sample	**90**	**99**
Total Dollars Chosen for Sample	**$257,568,932**	**$701,863,825**

4. Conducting Work Order Testing

Blue Ridge's work order testing focused on additions to intangible, distribution, and general plant in-service from 2008 through 2017, with an emphasis on CEP projects.

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

- Project descriptions, scope, and objective
- For CEP, whether the scope of work is includable within the CEP Deferral
- For CEP, whether the scope of work should generate revenue to be reflected in the Revenue Offset
- Project justifications and approvals
- Actual in-service dates for non-blanket projects within scope and for CEP from October 1, 2011, through December 31, 2017.
- Project budgeted and actual costs
- Variance from budget explanations
- Supporting cost detail for additions to plant
- Reasonableness of cost categories

[38] WP CEP PPS Sample and Judgement and WP Pulling Sample CEP.
[39] WP Non-CEP PPS Sample and Judgement and WP Pulling Sample Non-CEP.
[40] WP 17-2202-GA-ALT BRCS DR Set 1-9 REVISED Attachment A.
[41] Columbia Gas response to Blue Ridge Data Request 1.009 Attachment A Revised.
[42] Columbia Gas response to Blue Ridge Data Request 1.009 Attachment A Revised.

- Proper charge of the actual detailed cost to the proper FERC account
- For replacement projects, supporting detail for retirements, cost of removal, and salvage charged or credited to plant
- Timeliness of recording of asset retirements for replacement work orders
- Appropriate charge of cost of removal and salvage, if applicable
- Used and useful status of selected assets (determined by field review)

To satisfy the review of these areas of focus, Blue Ridge formulated the objective criteria into the following transactional testing steps, labeled T1 through T12.[43] Blue Ridge's observations and findings against the criteria follow.

T1: Is the scope of work attributed to the Ohio gas distribution function, and specifically, not related to an affiliate?

T2: For CEP projects placed in service from October 1, 2011, through December 31, 2017, does the project meet one of the following standards for inclusion in the CEP?
T2A: Replacement/ Public Improvement/Betterment project
T2B: Growth
T2C: Support Services
T2D: Information Technology

T3: Is the scope of work properly classified as capital and to the proper FERC 300 account as dictated by the FERC code of accounts?

T4: Does the project include detailed justification that supports that it was necessary, reasonable, and prudent?

T5 Does the work order generate revenue, and if so, is the CEP offset by the revenue produced?

T6: Are the work orders and/or projects properly approved?

T7: Are project costs within the approved budget? Are explanations and approvals provided for cost overruns 20% and greater?

T8: If the work order represents allocated charges, are the allocations reasonable?

T9: Do the Continuing property records support the asset completely and accurately?

T10: Are the cost categories (Payroll, M&S, etc.) not unreasonable and support the work order total?

T11: Has the Company accounted for retirements, cost of removal, and salvage for replacement work orders?

T12: For Replacement work orders, was the asset retirement date in line with the asset replacement date?

The results of the detailed transactional testing performed on the work-order sample are included in the workpapers.[44] Specific observations and findings about the testing are listed below.

T1: Is the scope of work attributed to the Ohio gas distribution function, and specifically, not related to an affiliate?

[43] WP Columbia Gas Testing Matrix on CEP and NON-CEP Samples Final.
[44] WP Columbia Gas Testing Matrix on CEP and NON-CEP Samples Final.

Based on the single-line-item description of the scope provided for blanket projects and the detailed scope provided for non-blanket projects, the work appears to be attributed to the Ohio gas distribution function. Allocations are discussed in testing step T8.[45]

Blue Ridge questioned inclusion of one work order/project (work order 8347.34130137197—Structure Minor Pl: 695400 – Activity Cost of $534,713). The project detail included SCADA work was identified. The Company explained that the equipment used for Distribution Operations that require heightened attention have SCADA installed. SCADA was installed in this work order to allow Gas Control to actively monitor the equipment.[46] This explanation is not unreasonable.

T2: For CEP projects placed in service from October 1, 2011, through December 31, 2017, does the project meet one of the following standards for inclusion in the CEP?

T2A: Replacement/ Public Improvement/Betterment project
T2B: Growth
T2C: Support Services
T2D: Information Technology

This testing step focused on CEP projects. The work orders/projects placed in service between October 1, 2011, and December 31, 2017, fit one or more of the criteria for inclusion in the CEP. While the blanket workorders/projects did not have detailed descriptions, the information provided supported their inclusion in the CEP. See further discussion about blanket projects at testing steps T6 and T11.

The Company purchases METSCAN (automatic meter reading devices—AMRD) and American Meters. The AMRDs and Meters are used for both installation of new services (Growth category) and replacement of service lines (Replacement for Age and Condition category). Since AMRDs are capitalized upon purchase, the Company cannot tell whether they are used for new service lines or replacement service lines when they are installed. Other than the targeted AMRDs from 2009 to 2014 as part of the IRP, AMRDs and meters are not allocated to the IRP. Therefore, by default, they are captured through the Growth category in the CEP, which has been the case since October 2011.[47]

The CEP work order sample contained three work orders for either Meters or AMRDs:

- 2014–2017: Work Order 0549.34D0342208—METSCAN, $2,667,010
- 2011–2014: Work Order 0567.34D00342011—American AR250, $1,000,887
- 2011–2014: Work Order 0556.34D00342014—American A1250, $3,092,629

Per Commission Order on November 28, 2012, in Case No. 11-5515-GA-ALT, the Company was to provide a plan to be initiated before April, 15, 2013, to complete the installation of AMRDs on inside meters that do not have AMRDs. The devices have been installed on all meters.[48] The Company will not ask for recovery of AMRD installed after December 31, 2013.[49] Blue Ridge was able to confirm that no AMRDs or Meters were charged to the CEP prior to 2014.[50]

[45] WP Columbia Gas Testing Matrix on CEP and NON-CEP Samples Final.
[46] Columbia Gas response to Blue Ridge Data Request 10-001.
[47] Columbia Gas response to Blue Ridge Data Request 10-004.
[48] Columbia Gas response to Blue Ridge Data Request 1-001.
[49] Commission Order on November 28, 2012, in Case No. 11-5515-GA-ALT page 8.
[50] WP Columbia Gas Testing Matrix on CEP and NON-CEP Samples Final.

T3: Is the scope of work properly classified as capital and to the proper FERC 300 account as dictated by the FERC code of accounts?

The work order/projects in the sample were appropriately classified as capital and charged to the proper Intangible, Distribution, and General Equipment Gas FERC 300 accounts. We found two items that warranted further review: meter relocations and a work order which recorded PISCC on capital activity from 2004 to 2008. These items are discussed below.

The Company moves meters from inside to outside residences, which is typically charged as an expense. When relocating meters is done in conjunction with service-line replacements (job type 565), the Company capitalizes the entire activity.[51] Blue Ridge does not disagree with the Company's process; however, it does give the Company latitude to not relocate meters until service lines are replaced.[52] The Company does not track the meters relocated on an annual basis and, therefore, does not know the cost, including installation, for relocated meters expensed and capitalized. The Company estimates they have 257,195 meters that remain inside as of December 31, 2017.[53] Blue Ridge recommends that this activity be tracked more closely so that the Company can demonstrate why the cost of meters moved from inside to outside should be capital and included in the CEP.

Work Order 9409.3404A034024—Post In Service Carrying Charges (PISCC) 2004–2008, $12,909,832. This cost represents the cost of capital from the in-service date until customer rates are adjusted to reflect the additional capital investment. It acts the same as AFUDC but for post-in-service rather than in CWIP. This particular work order was to account for the capitalization of PISCC provided in the approved Company stipulation filed on October 29, 2003. The PISCC was calculated on eligible investments from November 1, 2004, through November 1, 2008.[54] It is important to note that because of the early date, the PISCC did not impact the CEP. Blue Ridge reviewed the detail and, since the PISCC was stipulated, did not perform any further testing. These costs would have been subject to Commission review.

T4: Does the project include detailed justification that supports that it was necessary, reasonable, and prudent?

The Company provided detailed documentation that supported the specific work orders/projects in the sample. That documentation defined the scope of the project and, for the most part, the necessity of the project.

Of the 189 work orders sampled, 77 (40%) are blanket projects. Blanket projects do not have detailed justifications, as they are routine, on-going projects, such as growth, age and condition, service-line replacements, riser replacements, services, and house regulators and meters. The scopes of those projects are apparent and are justified through the Company's Capital Governance process discussed in testing step T6.

T5: Does the work order generate revenue, and if so, is the CEP offset by the revenue produced?

Blue Ridge identified several Growth- and Betterment-type work that has the potential to generate revenue. For example, work order 0555.34160124268 includes the installation of 700' of 6" pipe that is to be used for future growth. When asked about it, the Company indicated that this

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[51] Columbia Gas response to Blue Ridge Data Request 10-017b.
[52] Columbia Gas response to Blue Ridge Data Request 10-017b.
[53] Columbia Gas response to Blue Ridge Data Request 14-002.
[54] Columbia Gas response to Blue Ridge Data Request 11-001.

project was classified as growth to extend Columbia's mainline to serve new customers. When planning this growth project, it was recommended to extend a larger pipe (betterment) in certain areas that required it to ensure enough capacity to serve the area's future needs. The capital investment was included in the CEP deferral as the mainline was in-service. The betterment portion of the investment is Columbia's attempt to prudently install pipe to meet the anticipated future needs of the system rather than installing a minimum-required pipe for the current load and later having to replace the mainline to meet known growth needs at additional cost. [55]The Company was not unreasonable as the addition of pipe will avoid a potential duplicate replacement pipe cost as the growth materializes.

The Company identifies CEP revenue-generating projects through the use of Activity Codes.

Table 5: Activity Codes for New Business Projects

Type	Activity Code
Mains - New	555
Service Lines – New	563
Meters - New	567
Meter Installations - New	569
House Regulators – New	571

Through December 31, 2017, the Company has not recorded a revenue offset in the CEP Deferral. When asked for the reason, the Company responded that Columbia includes, as part of its workpapers to the CEP annual informational filing in Case Nos. 11-5351-GA-UNC and 12-3221-GA-UNC, a CEP-revenue offset calculation. To date, this calculation has not yielded a CEP-revenue offset. The 2017 CEP Annual Information filing, filed on April 2018, was the first filing that resulted in an estimated CEP-revenue offset.[56]

The Company "calculates incremental revenue by identifying increases/decreases in the annual average number of customers served by rate schedule since its last rate case. Columbia uses average number of customers rather than monthly change in accordance with an agreement with Commission Staff. At that time, using average number of customers was determined to be the best approach since it eliminated seasonal fluctuations. These variances in customer counts are then multiplied by a calculated average of non-equity revenue generated under that rate schedule and aggregated to determine the incremental change in revenue."[57]

However, subsequent follow-up resulted in the Company developing a more precise calculation by rate schedule and discovering a potential offset of $443,539 during calendar year 2015.[58] The Company stated, and Blue Ridge recommends, that it work with Staff to review this calculation and incorporate any necessary offset.[59]

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[55] Columbia response to Blue Ridge Data Request 10-8.
[56] Columbia Gas response to Blue Ridge Data Request 10-022.
[57] Columbia Gas response to Blue Ridge Data Request 13-001.
[58] Columbia Gas response to Blue Ridge Data Request 13-001, Attachment A.
[59] Columbia Gas response to Blue Ridge Data Request 13-001.

T6: Are the work orders and/or projects properly approved?

The specific work orders/projects included in the sample were properly approved. Blanket activities have a different approval process. They are not approved on an individual work order/project basis. The work is approved in conjunction with an overall budget process that identifies types of activities that need to take place. Those activities include service-line additions and replacement, service replacements, meters and AMR devices, riser replacements, and growth projects. Those types of projects have specific project codes.

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The NiSource Board of Directors approves the total capital budget. For Columbia Gas, that budget would include allocations for each budget category, including CEP and the IRP. Certain program numbers fall under this program:[60]

- 0549 - Automatic Meter Reading Devices (AMRD)—CEP
- 9901 - 0549 AMRD with a specific identifier (9901) to indicate inclusion in the IRP—IRP
    - The work order sample had five such work orders that were approved by the Commission for inclusion in the IRP (Case 08-73-GA-Alt. December 2008) and included in the capital plan.[61]
- 0567 - Meter Purchases, retirements are picked up on a 0568 blanket based on number of meters retirement and not directly linked to additions—CEP
- 0571 - House Regulators—New—CEP
- 0903 - General Structures—CEP
- 0915 - Miscellaneous primarily used for tool purchases—CEP
- 9109 - Specific budget created for Arena Building—CEP; the Company provided specific meeting minutes that support the approval to go forward with the Arena Building. [62]
- 9409 - Post-in-Service Carrying Charges (PISCC). The PUCO-approved stipulation in Case No. 94-987-GA-AIR et al. provided for the capitalization of PISCC on eligible plant investments that were placed in service between November 1, 2004, and November 1, 2008. This work order was utilized to capture this PISCC capitalization—NA
- 9501 - Specific budget created for assets acquired from Columbia Transmission, there is a corresponding asset impairment recorded to the same specific budget—CEP
- Job Type 563 - This represents new service lines and is considered growth (This job type does not have either retirements or cost of removal associated with it. See further discussion at testing step T11.)[63]
- Job type 565 - This represents service-line replacements (See testing step T11 for further discussion about retirements and cost of removal.) [64]

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[60] Columbia Gas response to Blue Ridge Data Request 4-001 – Response Other Blankets.
[61] Columbia Gas response to Blue Ridge Data Requests 10-018 and 9-002.
[62] Columbia Gas response to Blue Ridge Data Requests 10-009a.
[63] Columbia Gas response to Blue Ridge Data Request 4-001 – Response 563 Blankets.
[64] Columbia Gas response to Blue Ridge Data Request 4-001 – Response 565 Blankets.

- Job type 7737 - This represents riser and hazardous customer service lines (See testing step T11 for further discussion.) [65]

Blue Ridge was unable to review specific project approval documentation for Blanket work orders. Therefore, we reviewed the process used to propose an annual budget to NiSource and the process used by NiSource to approve the budget.

The Company's Capital Governance Policy guides the processes for the approval of the total capital budget, the Level of Signature Authority for the approval of specific work orders and subsequent change orders, and the overall approval of blanket work orders. Each year, the NiSource Board of Directors approves the total capital budget for NiSource the Company.[66] The budget includes allocations for Growth, Age and Condition, Betterment, Public Improvement, Shared Services, and the IRP.[67] The budget planning process is typical in that it starts from the bottom up and is approved from the top down. The Company is told how much they are allowed to spend for a particular budget year. Several departments are involved in the planning process, including Engineering, Finance, and Capital planning. They forecast new customer additions. All the operating companies use the same type of template to forecast what they will need for the upcoming year and the projection for two to three years out. Once NiSource approves the capital budget, it is fixed unless the companies ask for availability of additional funding. Some types of work that cannot be budgeted include Emergent or Public Improvement. When costs for those areas occur and rise, a formal review is conducted by the Financial Planning & Analysis and Capital Planning departments, which weighs the risks of not doing the projects. The Company monitors the projects internally using the following methods:

- Monthly review meetings
- Quarterly meetings to look at how the budget is moving along
- Priority Pipe reviews
- Earned Value reports
- Comparative variance analysis [68]

The Company budget process is comprehensive. The monitoring and shifting of costs is under the control of the operating companies. Even though the Company and NiSource have a solid process in place for the approval of spending, consideration must still be given to whether what the Company is asking for in terms of capital spending is appropriate and whether all the spending is necessary. Budget-to-actual variances are analyzed at the budget category level (e.g., Growth, Age and Condition). Prior to 2015, variance explanations were documented at the gas distribution segment level for all Columbia companies and not at the individual operating company (state) level.[69] The process of allocating the budget categories has changed over the period from 2008 to 2017. The current process, in place for 2015 to 2017, is completed in Excel and includes checks to ensure the allocation agrees to the overall approved budget. Prior to 2015, Columbia utilized a system called Budgetwiser to allocate and track the budget. This system is no longer in use.[70] Further discussion of budgets and variances is included in other sections of this report.

[65] Columbia Gas response to Blue Ridge Data Request 4-001 – Response 7737 Blankets.
[66] Columbia Gas response to Blue Ridge Data Request 9-001.
[67] Columbia Gas response to Blue Ridge Data Request 3-006.
[68] Columbia Gas interview conducted by Blue Ridge on July 28, 2018.
[69] Columbia Gas response to Blue Ridge Data Request 9-004.
[70] Columbia Gas response to Blue Ridge Data Request 9-003.

T7: Are project costs within the approved budget? Are explanations and approvals provided for cost overruns 20% and greater?

Of the total work orders in the sample, approximately 16% were over budget (30 of 189) by 20% or greater. In addition, another 77 work orders were blanket-type work orders, which are under the capital funding program discussed in testing step T6

Non CEP:

Seventeen non-CEP work orders were over budget by more than 20%. The Company provided reasons for the overruns. Eleven of the 17 were in the category of Age and Condition,[71] and the work was pipe replacement. This type of work deals with some unknowns, such as soil conditions or depth of pipe. Therefore, until the holes are dug, full knowledge of the activity is not necessarily known. Four of the work orders were Public Improvement. In those cases, requirements tend to change along the way based on the municipality, and that creates additional costs. Also, for all main replacements, the paving and seeding costs tend to keep going up. The Company's explanations were not unreasonable.

Table 6: Non-CEP Work Orders Over Budget More Than 20% (Explanations Not Unreasonable)[72]

Work Order	Description	Total
0557.34110115069	Install 2118'-6" Pmmp : Broadway : Wal	$80,561
0557.34120105858	Ss Tee 3w St, 6" : 665736	$183,213
0557.34160124700	Ss Fitting St, 12" : 665550	$427,331
0561.34120121840	Pipe, Pl, 6" : 463036	$641,826
0561.34140116876	Pipe, Pl, 6" : 463036	$481,959
7119.34100121126	Pipe, Pl, 4" : 463026	$1,012,058
7209.34110115368	Install 3,805'-2",6",&8" Pmmp : Arlington : Tol	$293,203
7333.34120115956	Insr-Wld End, 12" : 345250	$6,858,346
7445.34130093974	Pipe, Pl, 2" : 463016	$815,104
7799.34160062665	Repl 13948'-2",4",6", 8" Pmmp : Mound & Hi : Spr	$1,256,332
8103.34110121216	Inst.12300' Plas-Parma Amrp #2: Renwood: Renwood/W.54th	$1,530,373
8145.34120115646	Pm Relocate 5,130' Of 12" Wtmp : Secor : Tol	$4,300,462
8341.34120151286	Pipe, Pl, 2" : 463016	$1,149,611
8381.34130137554	Pipe, St Tr Wld, 12" : 464250	$1,453,997
8421.34130122816	Pipe, Pl, 6" : 463036	$583,928
8509.34140117005	Pipe, Pl, 4" : 463026	$1,244,031
0561.WP6416.1721	Pipe, Pl, 6" : 463036	$127,119

CEP:

Thirteen CEP work orders were over budget by more than 20%.

Work Order	Description	Total	Over budget Discussion
0555.34120122190	Instl 1680'-6"P-Ip-Betterment : Snow : Par	$285,979	Original budget was $235,402. Therefore, the project was over budget by $49,577. Columbia was unable to locate the policy required Level 1 variance explanation for this work

[71] Columbia Gas response to Blue Ridge Data Request 4-001.
[72] Columbia Gas response to Blue Ridge Data Request 4-001.

Work Order	Description	Total	Over budget Discussion
			order and was unable to provide an explanation for the variance. Blue Ridge recommends the cost overrun be disallowed from the CEP. [**ADJUSTMENT #1**].
0555.34130122453	Install 2803'4"3346'2"P-Ip : Englewood : N R	$333,353	The work order approval for the variance was done in accordance with the LOSA policy and the reasons were not unreasonable.[73]
0555.34150151995	Pipe, Pl, 2" : 463016	$9,768	The actual dollar overrun was minor and did not require either a level 1 or level 2 approval.[74]
0555.34160147410	Install: 93' 4" Pmmp : Maple : Zan	$25,315	The actual dollar overrun was minor and did not require either a level 1 or level 2 approval.[75]
0557.34160117980	Inst 229'-4",6" Cslp,Pmlp : John : Mau	$166,499	The work order approval for the variance was done in accordance with the LOSA policy and the reasons were not unreasonable.[76]
0559.34160088267	Pipe, Pl, 6" : 463036	$57,602	While this work order was over budget by 63%, the actual dollars were below the $30,000 that requires a Level 1 variance explanation. This explanation conforms to Company policy and is not unreasonable.
0561.34110136148	Install 400'-2"4"6"Pmmp,+ Wtmp : Stringtown : Gro	$120,211	This was a public improvement project and the overrun was generated by the municipality.[77]
0561.34160139991	Install 3600'-2"Pmmp : Skyline : Col	$701,219	This work order was over budget by more than 20%. The project estimate was $578,717, and the cost overrun was $122,502. The Company provided a variance report which explained that additional asphalt was required, additional flagger hours were required and 50 additional hours of sewer camera were required. The Company explained what was over budget but not what caused it. Therefore, Blue Ridge recommends that the CEP be reduced by the overrun since the Company could not explain the reasons behind the overrun.[78] [**ADJUSTMENT #2**]

[73] Columbia Gas response to Blue Ridge Data Request 1-14. Attachment J.
[74] Columbia Gas response to Blue Ridge Data Request 1-14. Attachment J.
[75] Columbia Gas response to Blue Ridge Data Request 1-14. Attachment J.
[76] Columbia Gas response to Blue Ridge Data Request 1-14. Attachment J.
[77] Columbia Gas response to Blue Ridge Data Request 4.001.
[78] Columbia Gas response to Blue Ridge Data Request 10-0012.

Work Order	Description	Total	Over budget Discussion
0565.34130062345	4"Sl - London Correctional : London Cor : Lon	$46,192	The original budget was $12,561; therefore, the project was over budget by $33,631. Columbia was unable to locate the policy required Level 1 variance explanation for this work order and was unable to provide an explanation for the variance. Blue Ridge recommends the cost overrun be disallowed from the CEP [**ADJUSTMENT #3**]
0573.34120136670	Heater G/O Convec : 315100	$219,002	This project was 30% over budget ($51k). The Company's explanation was not unreasonable. The Company stated that the manufacturer sent an improper heater. Therefore, the work was performed twice, which doubled the T&E dollars. The work order contained approximately $26,278 in outside labor and another $13,501 in internal labor for this CEP work order.[79]
8347.34130137197	Structure Minor Pl : 695400	$534,713	Permits and approvals by the state of Ohio required additional detailed building plans. The explanation was not unreasonable.[80]
9501.34150138531	Emco 10 : 416100	$31,397,235	These charges are related to Columbia's purchase of assets from Columbia Pipeline Group as a result of the 2015 separation of the Columbia Pipeline Group from NiSource. The work order was budgeted for $18.25 million, and the actual cost was $31.4 million. The Company explained that the $31.4 million represents the original book value of the assets, which is offset by accumulated depreciation, and a gas plant acquisition adjustment to record the lessor of net book value or fair market value.[81] The explanation is not unreasonable.
NCSF16COH20C	Parking Lot : 198200	$106,786	This work order was over budget by 85%.[82] The Company' explained that the work order included two separate service authorizations. The first is for Buckeye Asphalt for $57,750 and the other is for Fosco Cement for $45,076.5 so the total budget was actually

[79] Columbia Gas response to Blue Ridge Data Request 4.001.
[80] Columbia Gas response to Blue Ridge Data Request 4.001.
[81] Columbia Gas responses to Blue Ridge Data Requests 10-005 and 10-006.
[82] Columbia Gas response to Blue Ridge Data Request 14.001.

Work Order	Description	Total	Over budget Discussion
			$102,826.50. The total spend is $106,786 which is a 4% budget over run.[83] The explanation is not unreasonable.

T8: If the work order represents allocated charges, are the allocations reasonable?

Allocations to Columbia from an affiliate

For purposes of rate base, 100% of Columbia's distribution investments are considered jurisdictional. There are investments included in Columbia's plant balances that are either shared investments (buildings) or allocated investments (software).[84]

Columbia Gas does share its investment located in two buildings. The costs of these facilities are shared through the billing to the service corporation of approximately 96% of the total cost of service, which includes lease expense, parking expense, operation and maintenance expenses, depreciation, property taxes, excise taxes, income taxes and return on its investment. This cost of service, which is performed annually, reflects the use of the Company's most recent return authorized by PUCO. Historically, all Company revenue received through these transactions during the test year is treated as a credit to cost of service in rate case proceedings.

In addition, the Company shares its investment in the buildings (material fabrication) located in Bangs, Ohio. The costs of these facilities are shared through the billing to the service corporation of approximately 73% of the total cost of service, which includes lease expense, operation and maintenance expenses, depreciation, property taxes, excise taxes, income taxes, and return on its investment. This cost of service, which is performed annually, reflects the use of the Company's most recent return authorized by PUCO. Historically, all Company revenue received through these transactions during the test year is treated as a credit to cost of service in rate case proceedings

Software investments made by NiSource are allocated to the individual operating companies based on the approved allocation basis. The allocation basis used for any particular investment depends on the purpose of the software. Any other shared service investments would be allocated using these same approved bases.[85]

Affiliate allocations arise from work associated with software projects (FERC 303) and Buildings where the work has a common benefit to the Company and other affiliates, such as NiSource. General Equipment also falls into this category, such as the purchase of furniture for a common-use building or computers. In most instances, and whenever possible, those types of costs are directly charged to each company. We did not find any instances where an allocation was unreasonable. The following work orders required additional follow-up.

- Work Order NCSP16COMPLYC—Training and standards program, $54,491.45. This work order had charges allocated to the Company. The Company explained that the total cost of the program was $154,146, and the Company allocation was based on the number of employees. This allocation method is not unreasonable.[86]
- Work Order 9109.3411A034600—Improvements Leased Property, $30,090,840. This work

[83] Columbia Gas response to Blue Ridge Data Request 14.001.
[84] Columbia Gas response to Blue Ridge Data Request 1-023.
[85] Columbia Gas response to Blue Ridge Data Request 6-002.
[86] Columbia Gas response to Blue Ridge Data request 10-025.

order was for the Arena Building. No costs for this building were allocated. [87]

- Work Order 0889.3415A030026—GPS Support (Software), $955,883. The Company provided sufficient detail to determine that the allocations were not unreasonable. [88]
- Work Order NCSE16DPRMC—Computer Software 121000, $349,897. This investment is for the Damage Prevention Risk Model used for analyzing one-call tickets. These charges were 100% associated with Columbia's use/investment of the software, and there was no allocation of charges.
- Work Order NCSP16CDREPOC—Computer Software 121000, $343,859. This investment is associated with payment options available to customers. Therefore, the allocation basis used to allocate the costs was the number of retail customers for the operating companies using the software. Columbia's retail customers represented 36.83% of the total retail customers for operating companies utilizing the investment. The percentage calculation was derived by dividing the number of Columbia Retail Customers (1,417,407) by Total Retail Customers (3,848,620), resulting in the allocation percentage (36.83%).
- Work Order NCSP16PLNBDGTC—Planning and Budgeting Cap, $1,019,730. This investment is for the implementation of an upgraded planning and budgeting system. The allocation was calculated based on gross fixed assets, O&M expenses, and employees, resulting in a 15.03% allocation to Columbia. The allocation was not unreasonable.

<u>Application of Overheads</u>

Vacation and non-productive overheads represent the cost incurred as the result of vacation, holidays, and sick benefits for employees.

Labor overheads represent the cost incurred as the result of paying labor benefits and specific types of payroll taxes for employees.

Construction Overheads (i.e., supervision, engineering, general, & administrative costs), also referred to as SEGA, represent charges applicable to construction incurred by employees and activities where it is impractical to charge construction work orders directly

Allowance for Funds Used During Construction, (AFUDC) are applied to designated work orders which have received charges and have been classified to Construction Work In Progress (CWIP). The AFUDC rate is determined on a NiSource basis reflecting the weighted average cost of the Company's capital components.[89]

Vehicle and General Tool overheads represent the cost incurred as the result of using Company vehicles or equipment. [90]

Blue Ridge did not review the calculation of overheads or the application specifically in the scope of this review. However, the categories of overheads that the Company applies are typical for utilities and are not unreasonable.

T9: Do the Continuing property records support the asset completely and accurately?

The Company uses a current version of PowerPlant for its plant accounting records. That system has the ability to provide detailed information by account, by activity, and by amount for all work

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[87] Columbia Gas response to Blue Ridge Data Request 10-009.
[88] Columbia Gas response to Blue Ridge Data Request 10-007, Attachment a.
[89] Columbia Gas responses to Blue Ridge Data Requests 6-001 and 6-009.
[90] Columbia Gas response to Blue Ridge Data Request 6-001.

orders, including blankets.[91] Therefore, the Company was able to provide detailed additions to plant for each work order. Blue Ridge reviewed the categories of charges for each work order. We asked questions, and the Company was able to provide adequate responses to our requests. We did not find anything that was unreasonable. The Company was able to provide retirement information for units and dollars as well as cost of removal for specific work orders. The retirements and cost of removal for blankets are handled in a different manner as discussed within this report.

T10: Are the cost categories (Payroll M&S etc;) not unreasonable and support the work order total:

All the work orders had supporting detail for the amounts added to Plant in Service. Several charges required further review. Fifty-seven work orders had categories entitled *Truck Maintenance* or *Tool Maintenance* and also had charges for overhead allocations for Trucks and Tools. In addition, several of the non-CEP work orders had charges entitled *Outside Maintenance unidentified*. One work order had the category *Corrosion Maintenance*.[92]

The Company explained that Truck and Tool clearings are the same as Truck and Tool Maintenance. The clearing references were associated with pre-NiFit cost elements (pre April 2014), which were converted to new cost elements through NiFit and referenced as maintenance. The underlying activity is unchanged, and while the cost element references maintenance, it includes all overhead costs associated with the operation of the truck or tool (heavy machinery), such as fuel costs. If an employee, who is assigned to a truck or tool, codes labor to a capital work order, a proportionate amount of the truck and tool overheads are allocated to the same work order.[93]

The Company explained that Corrosion Maintenance is dictated by the accounting cost element selected when processing the transaction. The cost element does not dictate whether a charge is for capital or expense work, but it is used to provide the best explanation of the underlying activity. These particular charges were associated with the use of an outside engineering company to perform corrosion inspections during the installation of the pipe as well as inspect the AC mitigation installed, as this project was in the area of electric[94]

The Company's response is not unreasonable.

T11: Has the Company accounted for retirements, cost of removal and salvage for replacement work orders.?

Of the 189 work orders selected for testing, approximately 65 were of the type of work for which retirements would not be expected (such as job type 563, which represents service line additions, and other job types that were specific to growth; other examples include shared services, support services, and computer equipment purchases).

Of the 189 work orders, 17 non-CEP work orders were Job Type 7737, which are work orders that do not have retirements since they are customer owned.[95]

The remaining 107 work orders represented service line replacements, Pubic Improvement, replacements for age and condition, shared services, support services, and intangible software.

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[91] Interview of Major Events and IT conducted on July 2, 2018.
[92] Columbia Gas response to Blue Ridge Data Request 4-001.
[93] Columbia Gas response to Blue Ridge Data Request 10-023.
[94] Columbia Gas response to Blue Ridge Data Request 10-015.
[95] Columbia Gas response to Blue Ridge Data Request 10-021.

Where assets were retired, cost of removal was charged. Even in instances where pipe was retired in place, the Company had to perform some functions in order to relieve the pipe of gas and make it safe. Cost of removal is similar to depreciation expense in how it effects net plant. Cost of removal increases the reserve which decreases net plant. Therefore, to the extent cost of removal is not charged, it would overstate net plant.

Four work orders were for replacement work were identified that did not have Cost of Removal charges recorded. The Company stated that the cost of removal charges were inadvertently excluded from the original response. The Company was able to provide the cost of removal for the first three work orders listed and stated that no cost-of-removal charges were recorded for the last one listed. They could not provide an explanation for why cost of removal was not recorded. This incident appears to be isolated, and therefore, Blue Ridge does not have any specific recommendations. This work order is non-CEP.

- Work Order 7355.34120072925—Repl. 10840'-2",4",6",8" Pmmp: 8th: Market St Amrp Ph 1, $2,275,883–Cost of Removal subsequently provided
- Work Order 7377.34120062308—Repl 8809' 4",2" P-Mp: Kenton A A: Spr, $392,554–Cost of Removal subsequently provided
- Work Order 7445.34130093974—Pipe, Pl, 2": 463016, $815,104–Cost of Removal subsequently provided
- Work Order 7485.34130106479—Pipe, Pl, 2”: 463016, $370,100–No Cost of Removal and Company is unable to locate explanation documentation[96]

For job code 0565 (Service Line Replacements). When the jobs are put into service, they automatically trigger a retirement. The retirements are done by utilizing vintage year, pipe type (e.g., plastic), and location of the replaced service line, which identifies which service line to retire. The retirements are closed each month the way Blanket work orders are typically closed.[97]

The Company allocates service line retirements related to the IRP based on a ratio of those service lines to all service-line additions. The difference between the total service lines retirements and the amount of service line retirements allocated to the IRP is allocated to the CEP. The philosophy the Company uses for this process is as follows:

- Service lines are tracked in blanket work orders, which means the installation costs are not tracked separately, and the install costs are not tracked specifically to each service line replacement. Service line replacements are booked to a blanket account, and then individual installation units (units of property) are put into service using average cost by taxing district by vintage year. Service line additions are processed on a monthly basis. The total cost of each work order is divided by the quantity (number of service lines) of that work order to derive a monthly cost per unit. The cost per unit changes each month. Service line additions, and therefore, retirements, were allocated on average 75% IRP and 25% CEP from October 2011 through December 2017.[98]
- The average service line installation cost attributed to CEP ranged from $2,274 in 2011 to $3,451 in 2017 (job code 565 service line replacements), an increase of *51%*.
- Cost attributed to CEP ranged from $9.417 million in 2011 to $15.600 million in 2017, an increase of *65%.*

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[96] Columbia Gas response to Blue Ridge Data Request 11-003.
[97] Columbia Gas response to Blue Ridge Data Request 4-001 – Response 565 Blankets.
[98] Columbia Gas response to Blue Ridge Data Request 10-019 and Attachment A.

- During that same period, non-CEP installation costs averaged $1,960 in 2011 to $3,271 in 2017, an increase of *66%*.
- Cost attributed to non-CEP during that same period went up only *28%*.[99]
- Possible reasons for the increases in cost are discussed in other areas of this report.

Retirements are accounted for on blanket work orders. Therefore, individual retirements do not track back to an individual service line. Each installation generates a retirement unit, and that retirement unit is retired at an average unit cost.[100] Retirements occur on a one-month lag. Retirement costs are based on the original cost. The costs retired are determined by whether the asset is retired from a mass asset. When a retirement is a mass asset, PowerPlant uses an average cost of service lines installed with the same parameters (e.g., location, retirement unit, vintage) to retire the asset. If a retirement is not a mass asset, PowerPlant uses the actual cost.[101]

This method of retiring replacement service line and main assets is similar to using a weighted average unit cost inventory for M&S issues. Actual cost is not used, but a weighted average by vintage year and type of pipe is used. Service line replacements are numerous, and the use of this method saves time and is not unreasonable. If any potential risk exists it would be either the under/over statement of the IRP, which would result in the inverse to the CEP. Given that the IRP is already being collected in rates, it is not likely that the CEP would be overstated.

Salvage represents the proceeds from the sale of assets that are replaced by the Company. For purposes of the depreciation reserve, salvage is recorded as an increase in the depreciation reserve (FERC 108), which results in a corresponding decrease in net plant.

In the Gas business, assets are frequently retired in place whenever possible. Doing so decreases cost of removal by saving time and labor. Exceptions to that practice might include incidences such as a municipality requiring the removal of replaced assets or where not removing assets could represent a safety hazard. When assets are removed, they are typically sold as scrap. Under some circumstances, the scrap can be applied to a retirement work order and tied to a specific project. Columbia Gas uses blanket work orders to replace assets. The Company also uses a standard cost formula for the retirement of service lines and mains. Therefore, scrap is accounted for in its own work order(s) and charged against FERC 108 (reserve for depreciation). Regardless of how it is done, as long as FERC 108 is charged, the process is in accordance with FERC (CFR 18) and properly accounts for scrap. Scrap is also considered in the calculation of the net salvage or negative net salvage that is used in depreciation studies. The work orders we tested did not contain any salvage specifically included in each work order. This situation is not unusual since salvage is not a budget item. We do not see any issues in this area, and it appears that Columbia books salvage in accordance with FERC (CFR 18), which conforms to the manner in which most Gas utilities record salvage.

T12: For replacement work orders, was the asset retirement in line with the asset replacement date?

Blanket projects are closed every month. Certain types of job codes, such as 565 (service line replacements), are retired on an average cost basis as the units are added, so both the addition and retirements take place at the same time. Cost of removal is charged generally at the same time or can precede the actual retirements. (See testing step T11 above for a detailed discussion of job type 565 average costs for installations and retirements.)

[99] Columbia Gas response to Blue Ridge Data Request 10-019.
[100] Columbia Gas response to Blue Ridge Data Request 4-001.
[101] Columbia Gas response to Blue Ridge Data Request 10-019.

For other non-blanket work orders, the Company uses three dates.

1. The in-service date is the date the assets were identified as used and useful. Those assets are moved from CWIP (FERC 107) to CCNC (FERC 106) during the subsequent month-end closing process that the date was entered.
2. The completion date represents the date the project is 100% complete, except for the possibility of some late charges (e.g., restoration costs, late invoices). Columbia uses a late-charges wait period to account for the possibility of these late charges. Completed work orders are not unitized to Plant-in-Service (FERC 101) until after this wait period.
3. The close date represents the date that the project has been unitized to Plant-in-Service (FERC 101) [102]

The Company prepares a unitization backlog. That backlog is discussed in the Unitization Backlog section of this report.

Blue Ridge did not identify any significant timing issues between additions, retirements, and if applicable, cost of removal.

Insurance Recovery

The Company has not had any significant Distribution Plant events in the last 10 years that resulted in an insurance claim greater than $50,000. As of December 31, 2017, there are no insurance claims pending related to Distribution Plant that are not recorded or accrued that would be charged to capital.

The Company's deductible for property related to offices, service centers and warehouses is $250,000 and $1 million for all other Ohio Property. Claims under the stated deductibles are paid by Columbia and/or NiSource and are not recoverable under insurance.[103]

Unitization Backlog

Blue Ridge reviewed the unitization backlog for two reasons. First, it provides an indication of how well the Company controls the process, and second, if the backlog were both significant and old, it represents a potential retirement issue.

As of December 31, 2017, the Company had a unitization back log of $106.8 million. Of that $164 thousand was backlogged greater than 12 months, and another $4 million was backlogged between four to 12 months. The remainder of the $102.6 million in work orders is backlogged under 3 months. Of the $106.8, $36.4 million included CEP work orders, while IRP work orders made up the remaining $72.2 million.

Table 7: Statistics on Work Order Backlog[104]

Row Labels	Backlog Balance	# of Work Orders
Under 3 Month	$102,656,723	761
4 to12 Months	$4,052,181	3
Over 12 Months	$163,635	5
Grand Total	**$106,872,538**	**769**

[102] Columbia Gas response to Blue Ridge Data Request 2-006.
[103] Columbia Gas response to Blue Ridge Data Request 1-029.
[104] Columbia Gas response to Blue Ridge Data Request 1-027 Attachment A.

The Company uses three dates for the backlog report: (1) the in-service date, which is the date the assets were identified as used and useful, (2) the completion date, for projects which are 100% complete, except for some possible late charges or restoration costs, and (3) the close date, which represents the unitization date. The length of time for the work orders listed is the difference between completion date and December 31, 2017. The project dollars are included in the CEP at the in-service date.[105]

It is not uncommon in the utility industry, and in particular for gas utilities, to hold open (not unitize) projects until all the charges are in. The advantage is that it avoids duplicate work. Frequently, distribution projects are not complete because a company is waiting to complete paving and seeding. That process is normally dependent on contractor availability and weather conditions.

Even though the total dollar value in the work order backlog appears high, the fact that 96% of the work orders are backlogged under three months is an indication that the Company is adequately monitoring the backlog of work.

FIELD INSPECTIONS AND DESKTOP REVIEWS

For field inspections, Blue Ridge selected 11 locations, several with multiple assets. An additional 13 projects were selected for desktop review. The following criteria were used for the field inspection and/or desktop review:

- 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.
- 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 project was not over built or "gold plated."

Work orders / projects were excluded from selection for the following reasons:

1. The work was a blanket project, including multiple assets installed at various locations, making it impractical to locate. In most instances, the individual dollar value of each work order is small. Work orders in this category include the installation/replacement of service lines, riser replacements, services, house regulators, and meters. We did select one or more blanket projects for desktop review.
2. The dollars were a transfer or reclassification (reversal) of Completed Construction Not Classified (FERC 106).

The field observations were performed by Blue Ridge and Commission Staff with assistance from Company representatives. The field verifications were done on July 24, 2018, through July 27, 2018. Information for each work order / project was provided to the observation team and a standard questionnaire was completed for each location. Where possible, pictures were taken of the installed

[105] Columbia Gas response to Blue Ridge Data Request 1-027.

assets. The completed questionnaires and applicable pictures are included as workpapers with this report.

Blue Ridge concludes that the field-inspected assets were all used and useful,

The following projects were field inspected:

<u>CEP</u>

1. Work order 9109.3411A034600 - Improvements Leased Property: 336000
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $30,090,840
    c. Total Activity in Population: Shared Services Allocation
    d. Project Description: Move in to the newly constructed Arena Building, Columbus Ohio
    e. Project In-Service Date: 10/1/14
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
2. Work order 8475.34150151927
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $473,134
    c. Total Activity in Population: Growth
    d. Project Description: SCADA, Replace regulator and Heater System POD, for Ohio University Boiler Project load growth, Athens Ohio
    e. Project In-Service Date: 10/1/15
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
3. Work order 8475.34140151696
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $600,688
    c. Total Activity in Population: Growth
    d. Project Description: SCADA, Replace regulator and Heater System POD, for Ohio University Boiler Project load growth, Athens Ohio
    e. Project In-Service Date: 10/1/15
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
4. Work order 7607.34150151789 – Valve, Ball, 16”: 890156
    a. Type of field inspection: Desktop/Field
    b. Total Activity in Population: Betterment
    c. Project Description: Glatfelter, Chillicothe Ohio new business, rebuild/upgrade an existing POD (Point of Delivery), upgrade MP system and install new mains and GMB (Gas Measuring Billing) station at Glatfelter site
    d. Project In-Service Date: 10/1/16
    e. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
5. Work order 7607.34150151848
    a. Type of field inspection: Desktop/Field
    b. Total Activity in Population: Betterment/Growth
    c. Project Description: Glatfelter, Chillicothe Ohio new business, rebuild/upgrade an existing POD (Point of Delivery), upgrade MP system and install new mains and GMB (Gas Measuring Billing) station at Glatfelter site

   d. Project In-Service Date: 8/1/16
   e. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
6. Work order 8655.34160152208 – PM Sofidel: Pittsburgh: Us23
   a. Type of field inspection: Desktop/Field
   b. Total Activity in Population: Growth
   c. Project Description: Sofidel new customer service Circleville Ohio to include upgrades to POD, 11.8 miles of new pipe and installation of new GMB at Sofidel site
   d. Project In-Service Date: 12/1/17
   e. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
7. Work order 8655.34160152290
   a. Type of field inspection: Desktop/Field
   b. Total Activity in Population: Growth
   c. Project Description: Sofidel new customer service Circleville Ohio to include upgrades to POD, 11.8 miles of new pipe and installation of new GMB at Sofidel site
   d. Project In-Service Date: 12/1/17
   e. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
8. Work order 0561.34160139991 – Intall 3600’-2”Pmmp: Skyline: Col
   a. Type of field inspection: Desktop
   b. Final Project Costs: $701,219
   c. Total Activity in Population: Public Improvement
   d. Skyline Drive, City of Columbus, install 3,618 feet of 2, 6” pipe CEP Relocation due to new storm lines by the City
   e. Project In-Service Date: 12/1/17
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
9. Work order 0555.34120122190 – Instl 1680'-6"P-Ip-Betterment: Snow: Par
   a. Type of field inspection: Desktop
   b. Final Project Costs: $285,979
   c. Total Activity in Population: Growth/Betterment
   d. Project Description: Park Blvd, Parma Ohio, 2,4,6” Pipe upgraded to 6” (1,680 ft.) for new load growth (North Pointe Region)
   e. Project In-Service Date: 3/1/14
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
10. Work order NCSE16DPRMC – Computer Software : 121000
   a. Type of field inspection: Desktop
   b. Final Project Costs: $349,897
   c. Total Activity in Population: Shared Service Allocation
   d. Project Description: Recommended by the internal Damage Prevention team, Columbia Gas of Ohio purchased the excavation risk software add on for the Optimain Program to identify and manage high risk profile 811(Dig safe) tickets
   e. Project In-Service Date: 9/1/17
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful

11. Work order 8347.34130137197 – Structure Minor Pl : 695400
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $543,713
    c. Total Activity in Population: Growth
    d. Project Description: SWACO (Solid Waste Authority of Central Ohio) Landfill Gas Collection Site in Seeds Road Jackson Township OH
    e. Project In-Service Date: 8/1/14
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
12. Work order 9501.34150138531 – Emco 10 : 416100
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $31,397,235
    c. Total Activity in Population: Acquisitions
    d. Project Description: Acquisitions of former Columbia Gas Transmission assets POD (Point of Delivery)
    e. Project In-Service Date: 12/1/15
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
13. Work order 0567.34D00342014 – American Al250 : 416608
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs CEP: $3,092,629
    c. Total Activity in Population: Growth
    d. Project Description: Blankets for Meters, Truck, and software
    e. Project In-Service Date: 1/1/17
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful

<u>CEP & Non/CEP</u>

14. Work order 0567.34D00342011 – American AR250: 416614:
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs CEP: $1,000,887
    c. Final Project Costs Non-CEP: $1,860,474
    d. Total Activity in Population: Meters / Growth
    e. Project Description: Blankets for Meters, Truck, and software
    f. Project In-Service Date: 1/1/11
    g. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
15. Work order 0549.34D00342008 – Metscan Unit: 415000
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs CEP: $2,687,010
    c. Final Project Costs Non-CEP: $1,139,692
    d. Total Activity in Population: Growth/ Auto Meter Reading Devices
    e. Project Description: Blankets for Meters, Truck, and software
    f. Project In-Service Date: 1/1/17
    g. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful

<u>Non-CEP</u>

16. Work order 8759.34160152350
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $895,657
    c. Total Activity in Population: Age & Condition
    d. Project Description: Alley MP system, Chillicothe Ohio, non-CEP pipe replacement (6,160 feet of 6 and 8" pipe). This was phase 1 of the upgrade to Medium pressure (MP) from the previous Low Pressure (LP) system
    e. Project In-Service Date: 10/1/17
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
17. Work order 7785.34160152216
    a. Type of field inspection: Desktop/Field
    b. Final Project Costs: $919,905
    c. Total Activity in Population: Age & Condition
    d. Project Description: Poplar Street, Nelsonville Ohio, Non CEP pipe replacement (9,560 feet of Low pressure 2 and 4" leak prone pipe to Medium pressure system)
    e. Project In-Service Date: 10/1/17
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
18. Work order 7265.34110146029 - Install 39654'-2,4,6"Pl Pipe : Main : Gna
    a. Type of field inspection: Desktop
    b. Final Project Costs: $1,575,357
    c. Total Activity in Population: Age & Condition
    d. Project Description: Gnadenhutten Ohio, replace leak prone 2,3, 4,6"pipe replacement -Non CEP
    e. Project In-Service Date: 3/1/13
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
19. Work order 7411.34130116177 - Pipe, St Tr Wld, 20" : 464258
    a. Type of field inspection: Desktop
    b. Final Project Costs: $6,842,003
    c. Total Activity in Population: Age & Condition
    d. Project Description: Maumee River Crossing, Toledo pipe replacement Non CEP
    e. Project In-Service Date: 12/1/14
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
20. Work order 7799.34160062665 - Repl 13948'-2",4",6", 8" Pmmp: Mound & Hi : Spr
    a. Type of field inspection: Desktop
    b. Final Project Costs: $1,256,332
    c. Total Activity in Population: Age & Condition
    d. Project Description: Mound & High St, Springfield OH, Age and Condition Non CEP, pipe replacement
    e. Project In-Service Date: 11/1/17
    f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
21. Work order 8341.34120151286 - Pipe, Pl, 2" : 463016
    a. Type of field inspection: Desktop

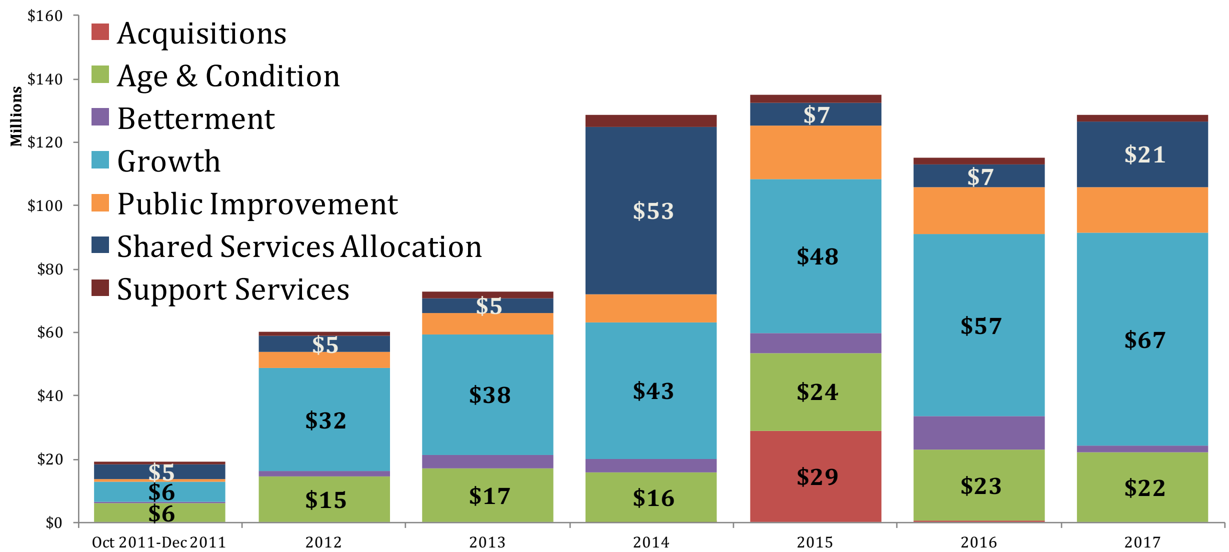
   b. Final Project Costs: $1,149,611
   c. Total Activity in Population: Age & Condition
   d. Project Description: Three Rivers, Age and Condition Non CEP, pipe replacement
   e. Project In-Service Date: 11/1/14
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
22. Work order 8103.34110121216 - Inst.12300' Plas-Parma Amrp #2: Renwood: Renwood/ W.54th
   a. Type of field inspection: Desktop
   b. Final Project Costs: $1,530,373
   c. Total Activity in Population: Age & Condition
   d. Project Description: All three work orders are in the same North Pointe Region (City of Parma) neighborhood. This was a age and condition Non CEP pipe replacement
   e. Project In-Service Date: 11/1/11
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
23. Work order 7119.34100121126 - Pipe, Pl, 4": 463026
   a. Type of field inspection: Desktop
   b. Final Project Costs: $1,012,058
   c. Total Activity in Population: Mains Replacement/ Age & Condition
   d. Project Description: All three work orders are in the same North Pointe Region (City of Parma) neighborhood. This was an age and condition Non CEP pipe replacement
   e. Project In-Service Date: 11/1/11
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful
24. Work order 7929.34080129187 - Pipe, Pl, 6": 463026
   a. Type of field inspection: Desktop
   b. Final Project Costs: $833,792
   c. Total Activity in Population: Mains Replacement/ Age & Condition
   d. Project Description: All three work orders are in the same North Pointe Region (City of Parma) neighborhood. This was an age and condition non-CEP pipe replacement
   e. Project In-Service Date: 6/1/11
   f. Additional Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent, and used and useful

CAPITAL SPENDING AND COST CONTAINMENT

CAPITAL SPENDING

Capital spending has increased significantly since the inception of the CEP as shown on the following graph.

Figure 1: CEP Capital Expenditures 2011–2017[106]



While there has been large Shared Services projects, such as the new Arena headquarters in 2014 and the information technology system upgrades in 2017 (see the discussion in the work order testing step T8), Growth-related activities is the largest annual spend category.

The following tables show the spending that the Company has made for Growth, Age and Condition, and Betterment by year from 2008 through 2017. Also, included is the final budget for the same categories by year.[107]

Table 8: Columbia Gas Capital Spending by Category[108]

Actuals		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Growth	Gross View	$ 15,313	$ 19,527	$ 17,363	$ 19,988	$ 32,631	$ 41,377	$ 42,132	$ 53,890	$ 64,345	$ 81,418
Betterment	Gross View	$ 7,740	$ 2,224	$ 1,265	$ 2,154	$ 2,147	$ 6,516	$ 5,473	$ 7,897	$ 16,713	$ 13,036
Age & Condition	Gross View	$ 90,538	$ 106,572	$ 112,878	$ 156,412	$ 184,932	$ 189,676	$ 183,628	$ 218,334	$ 231,701	$ 220,360

Approved		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Growth	Gross View	$ 20,630	$ 12,324	$ 16,500	$ 17,320	$ 32,670	$ 44,910	$ 41,100	$ 48,000	$ 55,000	$ 77,955
Betterment	Gross View	$ 6,437	$ 200	$ 1,250	$ 4,600	$ 3,900	$ 8,100	$ 15,600	$ 16,100	$ 20,500	$ 10,000
Age & Condition	Gross View	$ 77,898	$ 97,761	$ 104,500	$ 151,392	$ 188,475	$ 183,735	$ 180,000	$ 195,855	$ 198,000	$ 236,255

Final Budget		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Growth	Gross View	$ 20,630	$ 16,324	$ 16,100	$ 18,500	$ 32,670	$ 39,170	$ 41,900	$ 49,400	$ -	$ 80,945
Betterment	Gross View	$ 5,437	$ 590	$ 1,250	$ 2,600	$ 2,400	$ 8,300	$ 6,110	$ 9,000	$ -	$ 10,795
Age & Condition	Gross View	$ 77,898	$ 98,820	$ 108,442	$ 156,552	$ 184,475	$ 183,235	$ 186,315	$ 208,855	$ -	$ 220,794

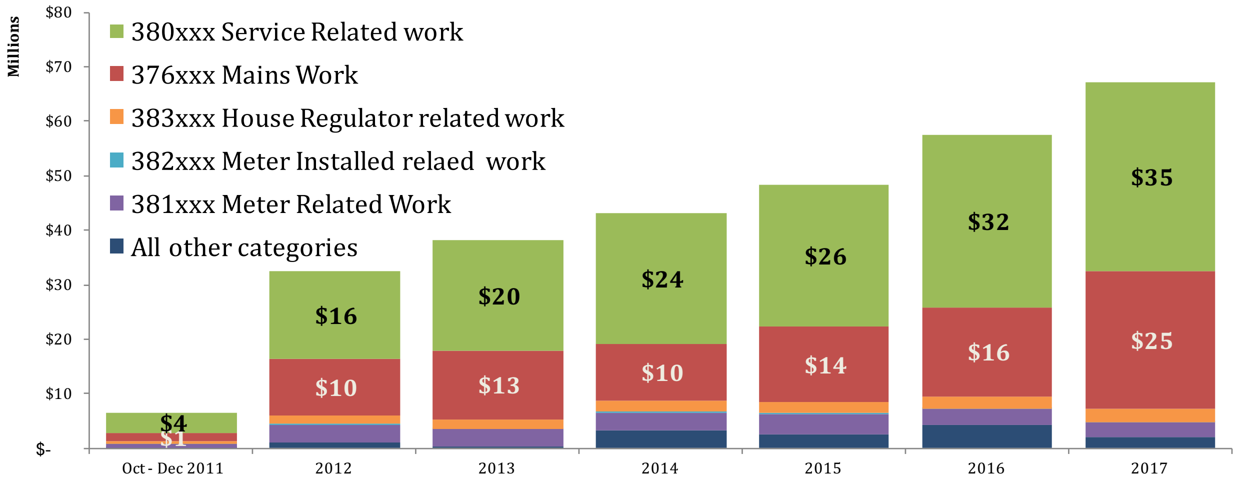
Growth Projects

Starting in 2012 (the first full year of the CEP) and continuing through 2017, the actual spend on growth increased 149.5%. From 2008 through 2011, the Company has seen an increase in growth,

[106] Columbia Gas response to Blue Ridge Data Request 1-009 Revised Attachment A.
[107] Columbia Gas response to Blue Ridge Data Request 9-004, 2008–2017 capital status reporting
[108] Columbia Gas response to Blue Ridge Data Request 9-004 Attachment A.

highlighted by the significant spike in 2012, the first full year of the CEP. (The program had begun in October 2011.[109]) Certain areas of the Company service territory have seen steady growth, which would contribute to the need for more spending. The Company has established new customer growth targets of net 1% by 2020 with focus on both new construction and propane and electric energy conversions.[110] Growth-related activities are driven as expected by Service and Main pipe-related activities as shown on the following graph.

Figure 2: CEP Capital Expenditures—Growth 2011–2017[111]



Age and Condition

The actual spend on Age and Condition increased 19% from 2012 through 2017. This type of spending is more discretionary than is Growth. Again, the spike in spending took place around the time the CEP started.

Betterment

The actual spend for Betterments, while far less in total dollars than both Growth and Age and Condition, showed an increase of 507% in 2017 as compared to 2012. Betterments are work done to increase pipe size to accommodate more throughput for existing customers or for future growth.

CEP-Related Cost per Main Mile Installed

Since a large contributor to the CEP is Service and Main pipe-related activities, the cost per main mile installed is an important monitor. Blue Ridge had the following observations associated with main-mile replacements.

- The cost per mile for main replacement for the CEP increased 23% from 2014 through 2017. The cost per main mile for IRP went up 7% in the same period. Data was not available for the CEP prior to 2014.[112]

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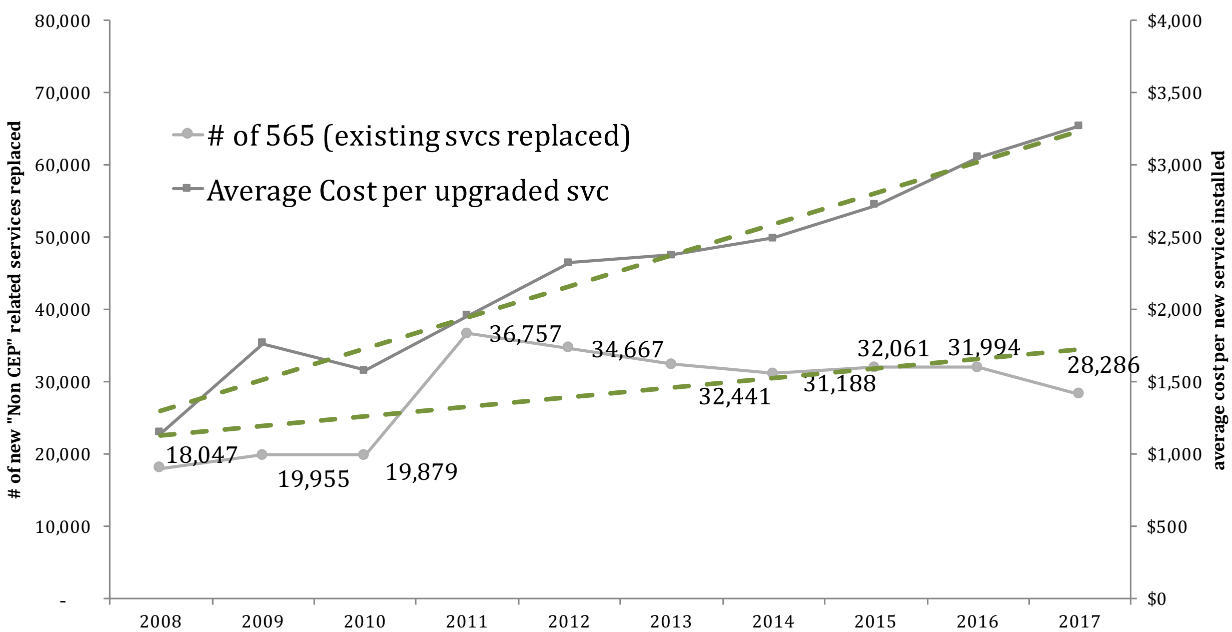
[109] Columbia Gas response to Blue Ridge data request 9-004, 2008–2017 capital status reporting.
[110] Columbia Gas response to Blue Ridge Data Request 10-024.
[111] Columbia Gas response to Blue Ridge Data Request 1-009 Revised Attachment A.
[112] Columbia Gas response to Blue Ridge Data Request 3-001.

- The cost per CEP service line replacement increased 37% from 2012 (the first full year of the CEP) through 2017.
- The cost per engineering designed service line replacement over 3" increased 163% from 2012 through 2017.
- The cost per mile for IRP service line replacement increased 41% from 2012 through 2017.[113]
- Services installed for Growth increased 41% from 2012 through 2017.
- Miles of main installed for Growth decreased 6% from 2012 through 2017, remaining relatively constant.
- The miles of main installed to increase capacity (betterment) averaged 10 miles per year from 2012 through 2017. Spikes occurred in 2016 and 2014.[114]

The CEP is a mechanism to allow recovery of large internal infrastructure and system upgrades. Also, a large segment of the CEP is to replace aging infrastructure based on Age and Condition. The non-CEP (IRP) program targets a known quantity and specific locations of leak-prone pipe (mains and services). Therefore, CEP budgets (and the resultant final annual spend rates) are fluid and to a large degree unknown and unbounded.

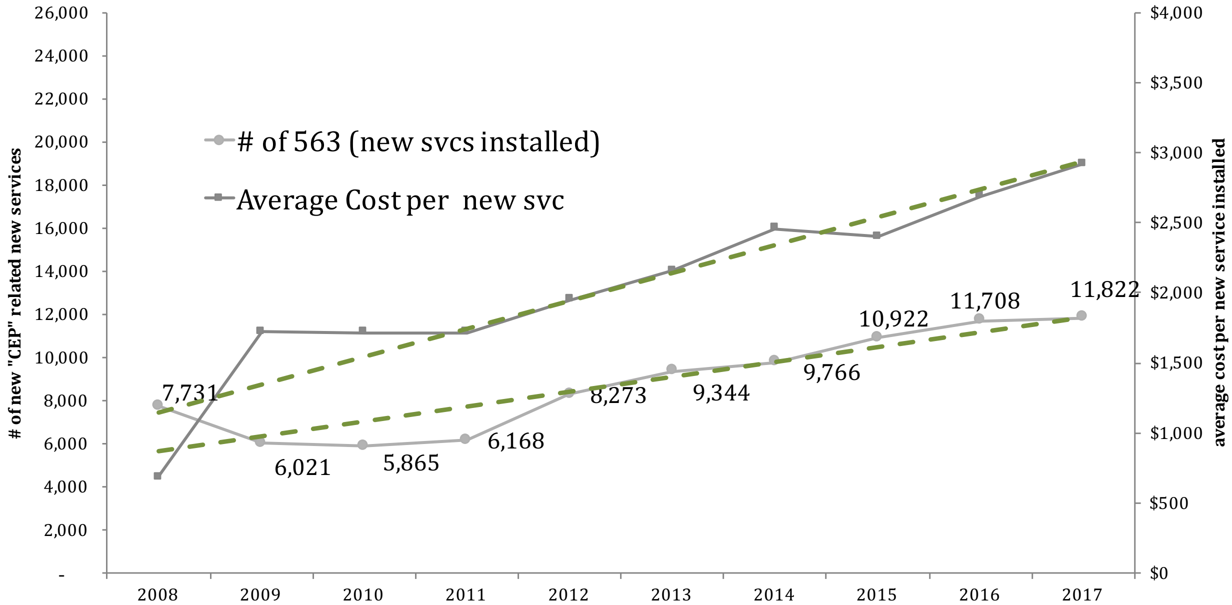
As the Company has indicated in the annual filings, CEP spend rates, which become the requested recovery, is expected to continue to rise significantly above the latest filed 2017 levels.

Figure 3: Non-CEP-Related Service Line Replacements (565 Blanket Job Types)[115]



[113] Columbia Gas response to Blue Ridge Data Request 3-002.
[114] Columbia Gas response to Blue Ridge Data Request 3-005.
[115] Columbia Gas response to Blue Ridge Data Request 10-019.

Figure 4: CEP-Related New Services (563 Blanket Type Jobs)[116]



In summary, CEP costs have increased and CEP spend rates are expected to continue to rise significantly over the coming years.

Cost Containment

Containing costs is key to controlling the significantly increasing costs associated with CEP-type projects. The Company discussed pressures on its capital budgets due to a constrained labor market and increased restoration requirements and permitting fees for local and state Government, as well as an increase in the volume of required relocation work.[117] This pressure was also observed during our onsite field audits. However, labor costs are the major contributor to the CEP costs. Contractor costs have affected the annual cost per total mile of main as shown in the following table.

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[116] Columbia Gas response to Blue Ridge Data Request 10-019.
[117] Columbia Gas response to Blue Ridge Data Request 3-008.

Table 9: Contractor Cost Impacts to the Annual Cost per Total Miles of Main[118]

Year	CEP Additions	Mainline Contractor Spend	Mileage	CEP Cost per Mile	Mainline Contractor Cost per Mile	Contractor % of CEP Cost per Mile
2011	$ 18,987,654	$ 6,433,619	52.06	$ 364,730	$ 123,582	34%
2012	$ 60,372,513	$ 17,324,222	93.02	$ 649,049	$ 186,248	29%
2013	$ 72,950,902	$ 16,700,678	84.47	$ 863,646	$ 197,715	23%
2014	$ 128,819,142	$ 16,123,382	99.54	$ 1,294,165	$ 161,981	13%
2015	$ 135,095,385	$ 26,346,020	116.20	$ 1,162,584	$ 226,725	20%
2016	$ 115,080,721	$ 30,558,385	135.89	$ 846,853	$ 224,872	27%
2017	$ 128,786,793	$ 37,551,790	129.45	$ 994,839	$ 290,076	29%

The mileage listed in the table above includes all main mile additions outside the IRP.

The Company acknowledges that the demand for qualified crews is increasing while the supply is decreasing. Contractor constraints are expected to continue in the foreseeable future.[119] Basic economics, therefore, dictates that when the demand goes up, and the supply either stays the same or is reduced, the cost tends to increase. One of the major drivers for the increasing contractor costs is the attrition of experienced contractors. Thus, smaller talent pools, due to the competition with other utilities performing infrastructure replacement programs, has resulted in increased costs.

The Company identified a number of key labor cost drivers and the steps it is taking to control costs:

- The revitalization of shale drilling in Ohio, causing the continued demand for natural gas qualified construction crews and resources, is stretching the market. Because of the demand, the supply of these crews is decreasing, especially with the additional pressure caused by retirement of seasoned employees. Over the past several years, Columbia has increased its monitoring of spend, standardized contracts, and standardized contract unit items. Columbia has also improved its planning process, giving contractors advanced visibility of upcoming work to improve resource allocation. This improvement allows contractors to do more work with fewer crews. Columbia conducts quarterly business reviews with each of its key gas contractors, during which the parties discuss Columbia's capital plan, the contractor's ability to support the capital plan, and issues impacting the contractors, such as labor constraints. Through these quarterly business reviews, the Company is able to share best practices among its contractor base on a number of topics, including attracting, hiring, training, and retaining qualified employees.[120]
- Increased demand for contractors and a tight labor market have put upward pressure on the overall cost to complete capital work. The Company has mitigated this by capping price increases for 2017 and 2018 at 2.2% in its current blanket construction contracts. However, there is no guarantee that this is achievable going forward.[121]

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118 Columbia Gas response to Blue Ridge Data Request 7-009; Mileage above includes all main mile additions outside the IRP.
119 Columbia Gas response to Blue Ridge Data Request 1-030.
120 Columbia Gas response to Blue Ridge Data Request 7-016.
121 Columbia Gas response to Blue Ridge Data Request 7-015.

- Through blanket contract negotiations, The Company is working with its construction contractors to secure the most cost-efficient and qualified contractors to do the work. The Company has also worked with the Ohio Laborer's District Council and its largest contractors to create an entry-level training program for new employees beginning careers in gas construction. The Company has recently begun a partnership with the Distribution Contractors Association and the American Gas Association to help community colleges develop distribution construction training programs. The goal of all this training is to reduce the amount of on-the-job training and to allow new employees to have a quicker transition to becoming productive, safe employees. This practice improves productivity and contains costs.[122]
- Utilizing contractors allows the Company to leverage contractors' scale and expertise as well as contractors' flexibility with regard to geography and schedules. With contractors performing the majority of capital work, the Company can staff resources during the construction season only rather than staffing for the entire year. NiSource and the Company continue to investigate opportunities to utilize the internal work force in circumstances where doing so would be optimal compared to utilizing contractors.[123]

Table 10: Approximate Percentage of Contractor Vs. In-House Labor Used for the Six Core Job Types Based on the Amount of Capital Investment[124]

Work Type[1]	2008 Historical %	2009 Historical %	2010 Historical %	2011 Historical %	2012 Historical %	2013 Historical %	2014 Historical %	2015 Historical %	2016 Historical %	2017 Historical %
Company (555)	2%	0.3%	8%	4%	1%	0.3%	0.4%	0.4%	0.7%	0.5%
Contractor (555)	98%	99.7%	92%	96%	99%	99.7%	99.6%	99.6%	99.3%	99.5%
Company (557)	0.8%	1.2%	2.1%	0.4%	0.1%	0.1%	1.4%	0.2%	1.3%	0.3%
Contractor (557)	99.2%	98.8%	97.9%	99.6%	99.9%	99.9%	98.6%	99.8%	98.7%	99.7%
Company (559)	2%	4%	3%	6%	1%	1%	0%	2%	1%	0%
Contractor (559)	98%	96%	97%	94%	99%	99%	100%	98%	99%	100%
Company (561)	0.5%	0.3%	0.3%	0.7%	0.2%	0.1%	0.1%	2.1%	0.1%	0.6%
Contractor (561)	99.5%	99.7%	99.7%	99.3%	99.8%	99.9%	99.9%	97.9%	99.9%	99.4%
Company (563)	33%	25%	28%	27%	23%	23%	20%	17%	12%	17%
Contractor (563)	67%	75%	72%	73%	77%	77%	80%	83%	88%	83%
Company (565)	28%	44%	44%	20%	18%	20%	20%	19%	20%	20%
Contractor (565)	72%	56%	56%	80%	82%	80%	80%	81%	80%	80%

[1] Data has been provided by the 6 core job types (555 - Growth Mains, 557 - Mains Replacement, 559 - Betterment, 561 - Public Improvement, 563 - Growth Services, 565 - Services Replacement

- The Company utilizes a standard competitive bidding process for all outside services spend greater than $250,000, including construction services, allowing the Company to drive down the cost of time and materials of all outside services.
- In 2009, the Company competitively bid three-year blanket construction contracts, effective in 2010. These contracts were extended through 2015 based on direct negotiations with contractors. In 2015, Columbia competitively bid five-year blanket construction contracts, effective beginning in 2016. The Company anticipates competitively bidding blanket construction contracts in 2019 that will be effective beginning in 2020. NiSource competitively bids any projects in excess of $250,000 that do not fall under the blanket contracts.

[122] Columbia Gas response to Blue Ridge Data Request 7-012.
[123] Columbia Gas response to Blue Ridge Data Request 7-011.
[124] Columbia Gas response to Blue Ridge Data Request 7-010.

- Some additional, more recent initiatives to manage contractor costs include the following measures:
  - Improved planning process giving contractors advanced visibility of upcoming work to improve contractor's resource allocation
  - Working with Laborer's Council to develop entry level training for employees entering the distribution workforce
  - Development of long-term strategic partnerships to reduce contractor contingency needs for short-term contracts (NiSource and the Company continue to investigate opportunities to drive efficiencies internally and with contractors.)[125]

Regarding cost containment, the Company has essentially four options:

- Pay what the market will bear
- Defer or eliminate work
- Negotiate prices and lock in longer-term contracts
- Hire and train in-house resources

The CEP costs are increasing. Part of the reason is due to the extent of work going on, which is discussed elsewhere in this report, and part of it has to do with rising contractor costs. The Company is taking steps to control contractor costs. Putting on more full-time staff would not appear to be a viable alternative. The construction season in the gas business is finite, and therefore, the Company would be overstaffed in non-construction months. Since the ability to perform maintenance also depends on weather conditions, the same would hold true for hiring additional maintenance staff. The Company is taking steps which appear to be not unreasonable to try to control costs.

The Company has an obligation to ensure its system is safe and reliable. Ensuring such includes having a systematic pipe replacement program. However, additional cost pressures are further exacerbating this constraint, and one can expect that under the current structure of the CEP program, each incremental asset replaced will continue to cost more going forward. Therefore, the annual amounts of requested cost recovery will likely continue to rise.

Blue Ridge concludes that the Company is implementing sound cost containment strategies. But although those strategies may be slowing the impact, they are not negating the fact that the Ohio pipe construction market is a constrained market, as are also the neighboring states which also have accelerated capital trackers and/or shale drilling.

[125] Columbia Gas response to Blue Ridge Data Request 7-009.

APPENDICES

Appendix A: Information Reviewed

Appendix B: Data Requests and Information Provided

Appendix C: Work Papers

Appendix D: Recast Plant in Service Schedules

Appendix A: Information Reviewed

The following are excerpts from the Commission Opinion and Order and the Combined Stipulation specifically related to the last Rate Case, PIS, and CEP are provided below.

Case No. 08-72-GA-AIR – Rate Case

On December 3, 2008, the Commission issued its Opinion and Order regarding Case No. 08-72-GA-AIR. The Order approved the following Stipulation Agreements with modifications:

- Stipulation Agreement filed on October 24, 2008 be approved

On page 6 of the Opinion and Order: As noted above, certain of the parties (stipulating parties) entered into a stipulation that was filed on October 24, 2008. The only issues not resolved in the stipulation are the rate design issues associated with the Small General Service Class, which will be discussed…

On page 25 of the Opinion and Order: The stipulation resolves all outstanding issues except the issues of rate design for the Small General Service Class. These issues were submitted to the Commission for its consideration. The stipulating parties agreed to submit pre-filed, written testimony on the issues and they waived the rights to cross-examine witnesses on the issues or to file briefs.

Regarding the IRP

On page 8 of the Opinion and Order: Authorized to establish an Infrastructure Replacement Program Rider (IRP) providing recovery for:

a) The future maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia to present an existing or probable hazard to persons and property, and the systematic replacement, over a period of approximately three years, of certain risers prone to failure if not properly assembled and installed. The replacement of customer-owned service lines and prone-to-failure risers was previously approved by the Commission in its opinion and order dated April 9, 2008, in Case No. 07-478-GAUNC;
b) The replacement of cast iron, wrought iron, unprotected coated steel, and bare steel pipe in Columbia's distribution system, as well as Columbia's replacement of company-owned and customer-owned metallic service lines identified by Columbia during the replacement of all the above types of pipe (referred to as the Accelerated Mains Replacement Program or AMRP); and
c) The installation, over approximately a five-year period, of Automatic Meter Reading Devices ("AMRD") on all residential and commercial meters served by Columbia.

Rider IRP shall be calculated using a rate of 10.95 percent (which represents the stipulated rate of return of 8.12 percent plus a tax gross-up factor of 2.84 percent). The IRP shall be in effect for the lesser of five years from the effective date of rates approved in this proceeding or until new rates become effective as a result of Columbia's filing of an application for an increase in rates pursuant to Section 4909.18, Revised Code, or Columbia's filing of a proposal to establish base rates pursuant to an alternative method of regulation pursuant to Section 4929.05, Revised Code.

Rider IRP shall provide for the recovery of the return of and on the plant investment, inclusive of capitalized interest or post-in-service carrying costs charges, and depreciation expense and property taxes. Rider IRP shall also reflect the actual annual savings of operations and maintenance expense as an offset to the costs that are otherwise eligible for recovery through Rider IRP.

Within 30 days of the Commission order adopting the stipulation, Columbia shall docket its initial Rider IRP prefiling notice. In years 2009 through 2012, Columbia shall docket its Rider IRP prefiling notice by November 30 of each year, with updated information filed by the following February 28. (The Commission directs Columbia to make such filings for Rider IRP, and the filings for Rider DSM discussed below, in a single new case each year.) Each year's prefiling notice will contain estimated schedules for the Rider IRP to become effective the following May 1. Staff will conduct an investigation of each annual Columbia filing and parties may file objections to the filings. If the staff determines that Columbia's application to increase Rider IRP is unjust or unreasonable, or if any other party files an objection that is not resolved by Columbia, an expedited hearing process will be established to allow the parties to present evidence to the Commission for final resolution.

The Rider IRP rate that becomes effective May 1, 2009, for the Small General Service Class shall not exceed $1.10 per customer per month. The stipulating parties agreed to caps of $2.20, $3.20, $4.20, and $5.20 per customer per month for the subsequent four years. If during any year of the first four years of the five-year duration of Rider IRP Columbia's IRP costs would result in a Rider IRP rate that exceeds the Rider IRP caps described above, Columbia may defer on its books any costs that it is unable to recover through Rider IRP because the Rider IRP rate would otherwise exceed the specified cap. Such costs shall be deferred with carrying charges at an annual rate of 5.27 percent, representing Columbia's long-term debt rate. Columbia may include such deferred costs in any subsequent Rider IRP application during the five-year duration of Rider IRP as specified herein, and recover the deferred costs as long as the inclusion of the deferred costs does not cause Columbia to exceed the Rider IRP cap in the subsequent year in which the deferred costs are included in the Rider IRP adjustment filing. Any deferrals remaining at the end of the five-year period shall not be recoverable by Columbia.

Regarding Depreciation

On page 11 of the Opinion and Order: The depreciation accrual rates proposed by Columbia, as modified in the staff report, should be approved.

On page 17 of the Joint Stipulation Agreement: The depreciation accrual rates proposed by Columbia, as modified in the Staff Report, are reasonable and Columbia should be authorized to revise its depreciation accrual rates as proposed in its Application.

On page 4 of Staff’s Report: The Applicant's current accrual rates were prescribed by this Commission in Case No. 05-114-GA-AAM. In Case No.08-75-GA-AAM, the Applicant filed a depreciation study prepared by its consultant, Gannett Fleming Valuation and Rate Consultants, Inc. The Applicant's accrual rates for most gas plant accounts were developed using the straight-line average service life method of depreciation. For certain General Plant gas accounts, the annual depreciation amounts were based on amortization accounting.

The Staff conducted a review of the depreciation study provided by the Applicant. The Staff finds itself in general agreement with the service life projected retirement dispersion and net salvage parameters proposed in Applicant's study. However, the Staff noted small differences in some accounts between the accrual rates proposed by the Applicant and those that the Staff calculated based on the parameters proposed.

The Staff recommended accrual rates are shown on Schedule B-3.2a. The Staff recommends that the Applicant be ordered to use the accrual rates shown on Schedule B-3.2a for book depreciation purposes, effective concurrently with customer rates resulting from this proceeding.

The Staff has long maintained that accrual rates should be thoroughly reviewed at least every three to five years. The Staff therefore recommends that in five years Applicant submit a depreciation study for all gas plant accounts.

The Staff's calculation of depreciation expense based on the adjusted jurisdictional plant in service balances at date certain and the accrual rates discussed above, is shown on Schedule B-3.2.

On Schedule B.2a of Staff's Report:

FERC-Description	Company Proposed Accrual Rate %	Staff Proposed Accrual Rate %
Distribution Plant		
374 Land and Land Rights		
375.34 Structures & Improvements - Meas. & Reg.	2.73	2.73
375.56 Structures & Improvements - Indust. Meas. & Reg.	3.85	3.75
375.7 Structures & Improvements - Other Dist. Sys.	1.33	2.51
375.7 Structures & Improvements - Other Dist. Sys. Other Small	4.05	4.05
Composite Account 375.7		2.71
375.8 Structures & Improvements - Communications Structures	2.00	2.00
376 Mains	1.91	1.86
378 Meas. & Reg. Station Equipment - General	3.14	3.19
379 Meas. & Reg. Station Equipment - City Gate	3.55	3.44
380 Sen/ices	3.00	3.20
381 Meters	2.39	2.28
381.1 Automated Meter Reading Devices	6.67	6.67
382 Meter Installations	2.00	2.19
383 House Regulators	3.57	3.57
384 House Regulator Installations	3.67	3.57
385 Industrial Meas. & Reg. Sta. Equipment	3.67	3.67
387 Other Equipment - General	6.18	5.83
387.4 Other Equipment - Customer Information Services	5.00	4.55
General Plant:		
391.4 Office Furniture & Equipment	5.00	5.00
391.5 Office Furniture & Equipment - Info. Sys.	20.00	20.00
392 Transportation Equipment	6.67	6.67
393 Stores Equipment	3.33	3.33
394 Tools, Shop & Garage Equipment	4.00	4.00
394.11 CNG Equipment	10.00	10.00
395 Laboratory Equipment	5.00	5.00

FERC-Description	Company Proposed Accrual Rate %	Staff Proposed Accrual Rate %
396 Power Operated Equipment	5.83	5.83
398 Miscellaneous Equipment	5.00	5.00

Regarding Plant

On page 25 of the Opinion and Order: The value of all of the company's property used and useful in rendering service to its customers affected by this application as of December 31, 2007, determined in accordance with Section 4909.15, Revised Code, is not less than $1,028,445,000 [NOTE: Total Rate Base].

On page 6 of the Joint Stipulation Agreement: The value of all of Columbia's property used and useful for the rendition of service to its customers, determined in accordance with Sections 4909.05 and 4905.15, Revised Code, as of the approved date certain of December 31, 2007, is $1,028,445,000 as shown on Stipulation Exhibit 1 [NOTE: Total Rate Base].

On page 3 of Staff's Report: As a result of Blue Ridge's investigation and the Staff review of the application, the Staff recommends certain adjustments be made to the Applicant's date certain plant investment for ratemaking purposes. These adjustments are identified below, summarized on Schedule B-2.2, and are reflected in the calculation of jurisdictional plant in service figures on Schedule B-2.1. <u>Elimination of Plant Sold</u>: The Staff and the Applicant adjusted several plant-in-service accounts to remove the cost of plant sold after the date certain and therefore is no longer in service. The Staff's adjustment is shown on Schedule B-2.2a.

On pages 49-62 of Staff's Report are the Schedule B (Rate Base Schedules)

On page 49 of Staff's Report, Staff recommends the following plant in service balances on Schedule B-1. The balances include Elimination of Plant Sold after date certain identified in Blue Ridge's investigation:

Major Property Groups	Applicant	Staff
Plant in Service	1,834,480	1,834,480
Depreciation Reserve	(672,347)	(672,347)
Net Plant in Service	1,162,133	1,162,133
CWIP	0	0
Working Capital	200,550	200,669
Other Rate Base Items	(233,041)	(341,015)
Rate Base	1,129,642	1,041,787

On page 50 of Staff's Report, Staff recommends the following plant in service balances on Schedule B-2:

Major Property Groups	Applicant	Staff
Intangible Plant	21,899,926	21,899,927
Distribution Plant	1,769,856,700	1,769,856,699
General	42,723,859	42,723,859
Total Plant in Service	1,834,480,485	1,834,480,485

Regarding Property Taxes

On page 9 of Staff's Report: Taxes other than income taxes were adjusted to reflect the proper base and latest known tax rates. For example, property taxes were computed by applying the latest known average tax rate to the date certain property valuation. Ohio Excise taxes were calculated to reflect taxes based on adjusted test year revenues. FICA, FUTA and SUTA taxes were calculated based on test year adjusted payroll. Moreover, the Applicant currently recovers a portion of Ohio Excise tax through a tax rider. The Applicant proposed that the entire Ohio Excise tax be recovered through the tax rider. Schedule C-3.17 provides a summary of the calculated taxes and the resultant adjustment of those taxes. The supporting calculations are detailed on Schedules C-3.17a through C-3.17h.

On page 33 of Staff's Report: IRP: Staff recommends Columbia also be authorized to record as a regulatory asset, the related depreciation and incremental property taxes on all investments for which it is seeking recovery through Rider IRP between the date the property is placed into service and the date recovery of the investment commences. Columbia should also be permitted to accrue Post-in-Service Carrying Costs (PISCC) on all investment between the date the property is placed into service and the date recovery of the investment commences. The PISCC rate should be determined annually based on Columbia's weighted cost of debt and should not be compounded.

Regarding Rate of Return

On page 25 of the Opinion and Order: Findings of Fact: (14) The current net operating income for the 12-month period ending September 30, 2008, is $54,322,000. The net annual compensation of $54,322,000 realized by the applicant represents a rate of return of 5.28 percent. The stipulating parties have recommended a rate of return of 8.12 percent. (15) Applying a rate of return of 8.12 percent to the rate base of $1,028,445,000 will result in an annual dollar return of $83,510,000. Under the stipulation, the parties agreed that the adjusted test year operating income was $54,322,000. This results in an income deficiency of $29,188,000, which, when adjusted for uncollectibles and taxes, results in a revenue increase of $47,143,000.

On page 26 of the Opinion and Order: Conclusions of Law: A rate of return of 8.12 percent is fair and reasonable under the circumstances of this case and is sufficient to provide the applicant just compensation and return on its property used and useful in the provision of service to its customers.

On page 7 of the Joint Stipulation Agreement: Columbia is entitled to an overall rate of return of 8.12% and based on the information contained in the record of this proceeding the Parties agree that annual revenues specified above shall provide Columbia with an opportunity to earn an overall return of 8.12%. The Parties agree that the corresponding return on equity is 10.39%. In agreeing upon this return on equity, the parties took into consideration the fact that investors may perceive Columbia to be less risky because of the alternative regulation provisions agreed to by the Parties and because of the levelized rate design proposed by Columbia. Accordingly, the Parties reduced Columbia's return on equity by 25 basis points in order to reflect this reduced risk perception.

Case No. 11-5351-GA-UNC – Capital Expenditure Program

On August 29, 2012, the Commission issued its Findings and Order regarding Case No. 11-5351-GA-UNC. The Order approved the following:

On page 1 of the Findings and Order: On October 3, 2011, Columbia filed an application for authority to implement a capital expenditure program (CEP) for the period of October 1, 2011, through December 31, 2012, pursuant to Sections 4909.18 and 4929.111, Revised Code. Additionally, Columbia seeks approval to modify its accounting procedures to provide for capitalization of post-in-service carrying costs (PISCC) on those assets of the CEP that are placed into service but not reflected in rates as plant in service, as well as deferral of depreciation expense and property taxes directly attributable to those assets of the CEP that are placed into service but not reflected in rates as plant in service. According to the application, a cumulative investment of $76 million is projected for Columbia's CEP. Columbia states that it is not requesting cost recovery as part of this application and that recovery of any approved deferrals will be requested in a separate proceeding. Columbia submits that approval of the application will not result in an increase in any rate or charge, and, therefore, the application should be considered as an application not for an increase in rates under Section 4909.18, Revised Code.

On page 11 through 13 of the Findings and Order: Section 4929.111(A), Revised Code, provides that a natural gas company may file an application with the Commission under Section 4909.18, 4929.05, or 4929.11, Revised Code, to implement a CEP for any of the following: (a) Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program; (b) Any program to install, upgrade, or replace information technology systems; (c) Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.

Section 4929.111(C), Revised Code, requires the Commission to approve the application, if the Commission finds that the CEP is consistent with the natural gas company's obligation under Section 4905.22, Revised Code, to furnish necessary and adequate services and facilities, which the Commission finds to be just and reasonable.

Upon review of Columbia's application and the comments filed by the parties, the Commission finds that the application should be approved, with the following modifications and clarifications:

(a) Columbia should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's sur-reply comments.

(b) Columbia should offset the monthly regulatory asset amount charged to the CEP by those revenues generated from the assets included in the CEP for SFV customers, non-SFV customers, and any other revenue sources directly attributable to CEP investments.

(c) Columbia should maintain sufficient records to enable Staff to verify that all revenue generated from CEP investments is accurately excluded from the total monthly deferral.

(d) Columbia should calculate the PISCC on assets placed in service under the CEP as recommended by Staff, such that the PISCC are determined by taking the previous month's ending gross plant balance (utilizing the one-month lag method), less associated depreciation and retirements, and multiplying it by the Company's monthly long-term cost of debt rate.

(e) Columbia should calculate the depreciation and property tax deferrals for the CEP in a manner consistent with Staff's recommendations.

(f) Columbia should docket an annual informational filing by April 30 of each year that details the monthly CEP investments and the calculations used to determine the associated deferrals, as recommended by Staff. The annual informational filings should include all calculations used to determine the monthly deferred amounts, including a breakdown of investments (by budget class), PISCC, depreciation expense, property tax expense, and all incremental revenue, as well as a capital budget for the upcoming year. The annual informational filings should also include an estimation of the effect that the proposed deferrals would have on customer bills, if they were to be included in rates.

(g) Columbia may accrue CEP deferrals up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the SGS class of customers to increase by more than $1.50/month. Accrual of all future CEP-related deferrals should cease once the $1.50/month threshold is surpassed, until such time as Columbia files to recover the existing accrued deferrals and establish a recovery mechanism under Section 4909.18, 4929.05, or 4929.11, Revised Code.

The Commission finds no merit in the arguments of OCC and OPAE that Columbia's application fails to provide a sufficient description of the proposed CEP or its total cost. The Commission finds that Columbia's application includes the necessary information required by Section 4929.111, Revised Code, regarding the types and amounts of the expenditures included in the CEP such that the Company has demonstrated that the CEP is consistent with the Company's obligation under Section 4905.22, Revised Code, to furnish necessary and adequate services and facilities, which the Commission finds to be just and reasonable. The Commission emphasizes, however, that Columbia has not requested, nor is the Commission granting, cost recovery for any CEP-related items. The Commission will consider the prudence and reasonableness of the magnitude of Columbia's CEP-related regulatory assets and associated capital spending in any future proceedings seeking cost recovery and the Company will be expected to provide, at that time, detailed information regarding the expenditures for our review. Additionally, the Commission finds that our approval of Columbia's application, as modified herein, will not result in an increase in any rate or charge. Accordingly, the application should be considered as an application not for an increase in rates under Section 4909.18, Revised Code.

With the above modifications and clarifications, the Commission finds Columbia's proposed CEP, as modified herein, to be both reasonable and consistent with Section 4929.111, Revised Code. Accordingly, Columbia is authorized, pursuant to Sections 4909.18 and 4929.111, Revised Code, to implement the CEP and modify its accounting procedures as necessary to carry out the implementation of the CEP for the period of October 1, 2011, through December 31, 2012, consistent with this finding and order.

On page 1 through 9 of the Application for CEP: Pursuant to Rev. Code §§ 4909.18 and 4929.111, Columbia Gas of Ohio, Inc. ("Columbia") files this Application with the Public Utilities Commission of Ohio, ("Commission") for authority to implement a capital expenditure program and to modify its accounting procedures to provide for: (1) capitalization of post-in-service carrying costs on those assets of the capital expenditure program that are placed into service, but not reflected in rates as plant in service; and, (2) deferral of depreciation expense and property taxes directly attributable to those assets of the capital expenditure program that are placed into service, but not reflected in rates as plant in service. In support of its Application, Columbia states:

1. Columbia is a natural gas company within the meaning of Rev. Code § 4905.03(A)(6), and as such, is a public utility subject to the jurisdiction of the Commission.

2. Columbia is proposing to implement a capital expenditure program for the period October 1, 2011 through December 31, 2012. During this period Columbia estimates its capital expenditure program will include a cumulative investment level of seventy-six million dollars that qualifies for the accounting treatment under Rev. Code § 4929.111(A).
3. Pursuant to Rev Code § 4929.111(B) Columbia includes as Attachment A hereto its estimated total cost of the capital expenditure program covered by this application. The amounts shown on Attachment A will be eligible for the accounting treatment described more fully hereinafter. The actual expenditures will vary by category. The total amount expended will also vary from year to year due to Columbia's management of its capital expenditures budget in the aggregate, rather than by individual categories, and due to the development of Columbia's capital expenditure budget based upon cash payments (Account 107) rather than the date plant becomes used and useful and transferred to plant in service (Account 101, Gas Plant In Service). This timing difference between the date cash payments are made and the date plant is placed into service will result in the total capital budget estimates detailed on Attachment A being different in a given year with a corresponding increase or decrease in the actual expenditures eligible for accounting treatment under Rev Code § 4929.111(B).
4. Columbia's capital allocation policy governs the allocation of capital, including the identification and prioritization of capital projects. The annual capital budget allocation approved by the NiSource Board of Directors is consistent with Columbia's obligations to furnish necessary and adequate services and facilities under Rev. Code § 4905.22. The following components are included in Columbia's capital expenditure program:
    a. <u>Replacement/Public Improvement/Betterment</u> – Replacement of facilities for any of the following reasons: (1) physical deterioration; (2) meeting the requirements of governmental authorities related to street and highway construction; (3) accommodating existing customer requests for facility relocation; and, (4) improving system operating conditions and ensuring adequate distribution system capacity and/or system reliability. This Replacement/Betterment category may include, but is not limited to, costs related to installation of and/or improvements to mains and service lines, wells, well and field lines, gathering lines, base gas, compressor stations, purification equipment, measuring and regulation stations, district regulator stations, excess pressure measuring stations, meters, meter sets, AMR devices. house regulators, and any associated buildings, land or land rights.
    b. <u>Acquisitions</u> - Costs related to purchase of gas transmission, distribution, or storage facilities. This category may include, but is not limited to, costs associated with the purchase of mains and service lines, wells, well and field lines, gathering lines, base gas, compressor stations, purification equipment, measuring and regulation stations, district regulator stations, excess pressure measuring stations, meters, meter sets, AMR devices, house regulators, and any associated buildings, land or land rights.
    c. <u>Growth</u> - Facilities required to provide service to new customers or to provide increased load capacity to existing customers. This category may include, but is not limited to, costs associated with the installation of and/or improvement to mains and services (including service line installations to new customers served by existing mains), district regulator stations, excess pressure measuring stations, meters, meter sets, AMR devices, house regulators, and any associated land or land rights.

   d. Support Services - Capital expenditures that are not directly related to gas facilities fall into this category which may include, but is not limited to, costs associated with the purchase of and/or improvements to buildings and structures (including associated land and land rights), environmental remediation at company owned facilities, office furniture and equipment, motorized equipment and trailers, power operated equipment, and other miscellaneous equipment.
   e. Information Technology - Capital expenditures related to technology and communications infrastructure. This category may include, but is not limited to, costs associated with purchase and installation of communications equipment (including associated buildings, land or land rights), data processing equipment, data processing software, and software licenses.
   f. Distribution Integrity Management Plan Implementation - Capital expenditures identified as necessary to implement a Distribution Integrity Management Plan process that may fall into any or all of the categories described above.
5. In all of the categories described above the costs include (where applicable) Supervisory, Engineering, General, and Administrative overheads, and Allowance for Funds Used During Construction, and are net of any contributions, deposits, or other aid to construction. None of the capital expenditures in the categories described above include costs targeted for inclusion in Columbia's Infrastructure Replacement Program or CHOICE/SSO Reconciliation Rider.
6. Columbia adheres to the FERC Unified System of Accounts prescribed for Natural Gas Companies and Generally Accepted Accounting Principles when accounting for the actual cost of capital projects. Pursuant to the FERC Unified System of Accounts, all amounts included are just and reasonable. Projects that are deemed "used and useful" in serving the needs of Columbia's customers are reported as in-service. Detailed gas plant accounting records are maintained to permit identification, analysis and verification of capitalized costs.
7. This Application will not result in an increase in any rate, joint rate, toll, classification, charge or rental. Therefore, this Application is an application not for an increase in rates under Rev. Code § 4909.18.
8. Rev. Code § 4929.111(A) authorizes a natural gas company to request approval of a capital expenditure program under Revised Code sections 4909.18, 4929.05 or 4929.11 to implement a capital expenditure program for any of the following:
   a. Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program;
   b. Any program to install, upgrade, or replace information technology systems;
   c. Any program reasonably necessary to comply with any rules, regulations, or orders of the commission or other governmental entity having jurisdiction.
9. Rev. Code § 4929.111(C) provides for the Commission's approval of a capital expenditure program if the Commission finds the natural gas company's capital expenditure program is consistent with the company's obligations to furnish necessary and adequate services and facilities under section Rev. Code § 4905.22.
10. Pursuant to Rev. Code § 4929.111(D) the Commission shall authorize a natural gas company to defer or recover in an application filed under Rev Code § 4929.111 the following:
    a. A regulatory asset for post-in-service carrying costs on that portion of the capital expenditure program assets that are placed in service but not reflected in rates as plant in service;

b. A regulatory asset for the incremental depreciation on that portion of the assets of the capital expenditure program that are placed in service but not reflected in rates as plant in service; and,
c. A regulatory asset for the incremental property taxes directly attributable to the assets of the capital expenditure program that are placed in service but not reflected in rates as plant in service.

11. Rev. Code § 4929.111(F) authorizes a natural gas company to make any accounting accruals, necessary to establish the regulatory assets authorized under Rev. Code § 4929.111(D), in addition to any allowance for funds used during construction. Pursuant to Rev. Code § 4929.111(G) any accrual or deferral for recovery shall be calculated in accordance with the system of accounts established by the Commission under Rev. Code § 4905.13.
12. Revised Code § 4905.13 authorizes the Commission to establish systems of accounts to be kept by public utilities and to prescribe the manner in which these accounts shall be kept. In Chapter 4901:1-13-01, Ohio Administrative Code the Commission has adopted the Uniform System of Accounts ("USOA") for gas utilities established by the Federal Energy Regulatory Commission ("FERC") for use in Ohio. For Ohio regulatory purposes, the system of accounts is only applicable to the extent that it has been adopted by the Commission. Therefore the Commission may modify the USOA prescribed by FERC as it applies to utilities within the state of Ohio.
13. Pursuant to Rev. Code § 4929.111 (A-F) Columbia hereby requests approval of its capital expenditure program, and requests accounting authority to capitalize related carrying costs and defer related depreciation and property tax expense. Specifically, Columbia requests it be permitted to revise its accounting procedures to provide for the following with respect to its capital expenditure program:
    a. Authority to record as a regulatory asset all post-in-service carrying costs in Account 101, Gas Plant in Service, Post-In-Service Carrying Costs ("PISCC"). PISCC accounting treatment shall commence when the assets of the capital expenditure program are placed into service and shall cease when rates reflecting the costs of those assets become effective. All PISCC shall be calculated, for every investment in the capital expenditure program, based on Columbia's cost of longterm debt.
    b. Authority to record as a regulatory asset depreciation expense and property taxes on all investment in Columbia's capital expenditure program between the time assets are placed in service, but not reflected in rates as plant in service. This deferred accounting shall cease when rates reflecting the deferred depreciation expenses and property taxes become effective. Deferred depreciation expense and property taxes will be reflected in a sub-account of Account 182, Other Regulatory Assets, and be calculated as follows.
        i. Deferred property taxes shall be calculated, for every investment in the capital expenditure program, at Columbia's estimated composite property tax rate and deferred in a special subaccount of Account 182-Other Regulatory Assets-Deferred Taxes.
        ii. Deferred depreciation expense shall be calculated, for every investment in the capital expenditure program, at the applicable Commission-approved depreciation rates and recorded in a special subaccount of Account 182-Other Regulatory Assets-Deferred Depreciation
14. The PISCC accounting treatment requested in this Application is not a matter of first impression for the Commission. The requested accounting treatment is consistent with

that previously set forth in the Fourth Amendment to Joint Stipulation and Recommendation in Case No. 94 -987-GA-AIR et al. In that stipulation PISCC treatment was established for all investments placed into service between the dates November 1, 2004 through December 31, 2008. Said stipulation was approved by the Commission in an Entry dated March 11, 2004, and an in Entry on Rehearing dated May 5, 2004. In addition, Columbia had previously received approval to capitalize PISCC on all investments otherwise eligible for an "Allowance for Funds Used During Construction" with in service dates between December 31, 1990 and December 3, 1993 in Case No,. 91-195-GAAIR et al. pursuant to the Commission's Opinion and Order in that case issued November 27,1991.

15. In this Application Columbia is requesting only the accounting authority described above. Columbia is not requesting recovery of any of the deferred amounts as part of this Application. Recovery of any amounts deferred pursuant to approval of this Application will be addressed in a separate proceeding. The requested approval of the capital expenditure program and change in accounting procedure does not result in any increase in rate or charge, and the Commission can therefore approve this application without a hearing.

On April 26, 2013, the Company provided one annual report with the required information pertaining to CEP/PISCC for the previous year. 2013-2017 annual information is provided in a separate docket (see below).

Case No. 12-3221-GA-UNC – Capital Expenditure Program Modification

On October 9, 2013, the Commission issued its Findings and Order regarding Case No. 12-3221-GA-UNC. The Order approved the following:

On page 1 through 6 of the Findings and Order:

(2) On August 29, 2012, in Case No. 11-5351-GA-UNC, et al. (11-5351), the Commission modified and approved Columbia's application for authority to implement a capital expenditure program (CEP) for the period of October 1, 2011, through December 31, 2012, pursuant to Sections 4909.18 and 4929.111, Revised Code. The Commission approved Columbia's request to modify its accounting procedures to provide for capitalization of post-in-service carrying costs on those assets of the CEP that are placed into service, but not reflected in rates as plant in service, as well as deferral of depreciation expense and property taxes directly attributable to those assets of the CEP that are placed into service, but not reflected in rates as plant in service. The Commission authorized Columbia to accrue CEP-related deferrals only up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the Small General Service (SGS) class of customers to increase by more than $1.50 per month (deferral cap). At that point, accrual of all future CEP-related deferrals is required to cease, until such time as Columbia files to recover the existing accrued deferrals and establish a recovery mechanism under Section 4909.18, 4929.05, or 4929.11, Revised Code. The Commission also required Columbia to docket an annual informational filing by April 30 of each year that details, inter alia, the monthly CEP investments and the calculations used to determine the associated deferrals. (CEP Order at 11-13.)

(3) On December 24, 2012, Columbia filed an application, pursuant to Sections 4909.18 and 4929.111, Revised Code, seeking authority to continue its CEP, including deferral of the related carrying costs, depreciation expense, and property tax expense, in 2013 and succeeding years,

up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the SGS class of customers to increase by more than $1.50 per month. Columbia proposes to compute and defer the cost of its CEP-related investments in accordance with the CEP Order. According to the application, a cumulative investment of $72 million is projected for Columbia's CEP during the period from January 1, 2013, through December 31, 2013. Columbia states that it is not requesting cost recovery as part of this application and that recovery of any approved deferrals will be requested in a separate proceeding. Columbia submits that approval of the application will not result in an increase in any rate or charge, and, therefore, the application should be considered as an application not for an increase in rates under Section 4909.18, Revised Code.

(4) Additionally, Columbia states that it will include in its future annual informational filings all of the information required by the Commission in the CEP Order, including the Company's projected capital expenditures budget for the current and following calendar year. Columbia proposes that the projected CEP investments in the annual informational filing be the maximum allowable level of investment eligible for deferral in accordance with Section 4929.111(B), Revised Code. Columbia asserts that the accounting treatment requested in its application is consistent with Staff's recommendations, as approved by the Commission, in 11-5351.

(5) On April 26, 2013, Columbia docketed its annual informational filing in 11-5351 (2013 filing).

(6) By entry issued in the above-captioned cases on June 11, 2013, a comment period was established in order to assist the Commission in its review of Columbia's application. Pursuant to the entry, initial and reply comments were due to be filed by July 11, 2013, and July 25,2013, respectively.

(7) In accordance with the established procedural schedule, comments were filed by Staff on July 11, 2013. No other comments were filed in these proceedings.

(8) In its comments. Staff emphasizes that, because Columbia seeks approval to continue the CEP and the associated deferrals until the deferral cap is reached, no further applications will be forthcoming from the Company until that point is reached. As Columbia's annual informational filings would stand in place of future applications. Staff explains that it reviewed and considered both the application filed in the present cases and the 2013 filing in 11-5351, in the course of developing Staff's comments and recommendations. Staff finds that Columbia's application and the 2013 filing comply with the CEP Order and, accordingly, recommends that the Company's application be approved, subject to Staff's further recommendations.

(9) Specifically, Staff recommends that the Commission establish a process to permit intervening parties and Staff to object to continued authority for Columbia's CEP and related deferrals through a review of the Company's annual informational filings. Staff states that, under Columbia's proposal to continue the CEP and associated deferrals until the deferral cap is reached, there is no provision for intervening parties or Staff to object to any of the information provided by the Company in its annual informational filings. Staff proposes a 30-day automatic approval process that would require Staff and any intervening party to file objections to the information, or lack thereof, contained in Columbia's annual informational filings. Staff notes that, if there are no objections filed within 30 days of the date on which Columbia's annual informational filing is docketed, the Company's CEP and ongoing deferral authority would be deemed approved. Staff further notes that, if Staff or any intervening party

files objections within 30 days, an attorney examiner appointed by the Commission should issue an entry soliciting comments on the matters raised in the objections. Staff asserts that its proposal would provide for the efficient process that Columbia seeks, while allowing Staff and interested parties the opportunity to review the Company's annual informational filings, which was contemplated with the Commission's adoption of the annual informational filing requirement in 11-5351.

(10) Additionally, Staff recommends that the Commission clearly state that approval of Columbia's CEP and the associated deferrals does not guarantee recovery of CEP expenditures or deferrals. Staff advises the Commission to make clear that only deferral authority is approved in these cases and that Columbia's eligibility for recovery of the deferred amounts, including, but not limited to, issues such as prudence, proper computation, proper recording, and reasonableness, will be considered when the Company applies to recover the authorized deferrals.

(11) Section 4929.111(A), Revised Code, provides that a natural gas company may file an application with the Commission under Section 4909.18, 4929.05, or 4929.11, Revised Code, to implement a CEP for any of the following:

a. Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program;
b. Any program to install, upgrade, or replace information technology systems;
c. Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.

Section 4929.111(C), Revised Code, requires the Commission to approve the application, if the Commission finds that the CEP is consistent with the natural gas company's obligation under Section 4905.22, Revised Code, to furnish necessary and adequate services and facilities, which the Commission finds to be just and reasonable.

(12) Upon review of Columbia's application and Staff's unopposed comments, the Commission finds that the Company has demonstrated that the CEP is consistent with its obligation under Section 4905.22, Revised Code, to furnish necessary and adequate services and facilities, which the Commission finds to be just and reasonable. Further, the Commission finds that Columbia's application will not result in an increase in any rate or charge. Accordingly, the application should be considered as an application not for an increase in rates under Section 4909.18, Revised Code.

(13) With the modifications and clarifications set forth below, the Commission finds Columbia's proposed CEP, as modified herein, to be both reasonable and consistent with Section 4929.111, Revised Code. Accordingly, Columbia is authorized, pursuant to Sections 4909.18 and 4929.111, Revised Code, to implement the CEP and modify its accounting procedures as necessary to carry out the implementation of the CEP, consistent with this finding and order and the CEP Order, in 2013 and succeeding years, up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the SGS class of customers to increase by more than $1.50 per month.

(14) While the Commission approves Columbia's application for 2013 and succeeding years, we agree with Staff that a process should be adopted to allow interested persons and Staff to comment on the information provided by the Company in its annual informational filings due on April 30 of each year (CEP Order at 12). Therefore, the Commission directs that any comments and reply comments should be filed within 30 days and 40 days, respectively, of the

date of Columbia's annual informational filing. After receipt of each annual informational filing and review of any comments submitted, the Commission will determine whether there should be further review of Columbia's approved deferral authority at that time. If the Commission finds such further review to be necessary, within 60 days after the filing of each annual informational filing, an appropriate procedure for the review will be established. If such a review is initiated, Columbia may continue to accrue appropriate deferrals, unless and until the Commission orders otherwise. The Commission notes that Columbia's annual informational filings, as well as any comments and reply comments, should be filed in the above-captioned cases. With these modifications, we find that Columbia's application should be approved, subject to our review of the Company's annual informational filings and any comments or reply comments filed in response.

(15) Additionally, the Commission emphasizes that, consistent with Columbia's application, we approve the Company's request for deferral authority, but do not authorize recovery of the deferred amounts at this time. The question of recovery of the deferred amounts, including, but not limited to, issues such as prudence, proper computation, proper recording, and reasonableness, will be considered when Columbia files an application to recover the deferred amounts. As we stated in the CEP Order, the Commission has not granted cost recovery for any CEP-related items, and the prudence and reasonableness of the magnitude of Columbia's CEP-related regulatory assets and associated capital spending will be considered by the Commission in any future proceedings seeking cost recovery, at which time the Company will be expected to provide detailed information regarding the expenditures for our review (CEP Order at 13).

On page 1 through 7 of the Application: In Case Numbers 11-5351-GA-UNC and 11-5352-GA-AAM Columbia Gas of Ohio, Inc ("Columbia") sought approval of a capital expenditure program ("CEP") and related accounting authority for part of 2011 and calendar year 2012. The Commission approved Columbia's application, with modifications, by Finding and Order dated August 29, 2012. Pursuant to Rev. Code 4909.18 and 4929.111, Columbia files this Application with the Public Utilities Commission of Ohio, ("Commission") for authority to continue its capital expenditure program in 2013 and succeeding years, and for authority to defer related PISCC, depreciation expense and property taxes on those assets of the capital expenditure program that are placed into service, but not reflected in rates as plant in service. In support of its Application, Columbia states:

1) Columbia is a natural gas company within the meaning of Rev. Code 4905.03(A)(6), and as such, is a public utility subject to the jurisdiction of the Commission
2) In Case Nos. 11-5351-GA-UNC et al. the Commission authorized Columbia to implement its capital expenditure program and modify accounting procedures as necessary to carry out the implementation of the capital expenditure program for the period of October 1, 2011, through December 31, 2012. The Finding and Order requires Columbia to make annual informational filings on April 30 of each year. The annual filing must detail the monthly CEP investments and the calculations used to determine the associated deferrals. The annual informational filings must include all calculations used to determine the monthly deferred amounts, including a breakdown of investments (by budget class), post-in service carrying charges ("PISCC"), depreciation expense, property tax expense, and all incremental revenue, as well as a capital budget for the up-coming year. The annual informational filings should also include all estimation of the effect that the proposed deferrals would have on customer billing, if they were to be included in rates. The Finding and Order further provides that Columbia may accrue CEP deferrals up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the SGS class of customers

to increase by more than $1.50/month. Accrual of all future CEP-related deferrals will cease once the $1.50/month threshold is reached, until such time as Columbia files to recover the existing accrued deferrals and establish a recovery mechanism under Rev. Code§ 4909.18, 4929.05, or 4929.11. The final component that must be included in these informational filings is the projected annual CEP expenditure for current year which would be the maximum incremental investment available for deferral treatment under Rev. Code§ 4929.111(A) for the calendar year, unless the commission in its discretion authorizes additional deferral under Rev Code§ 4929. 111(3)(D).

3) In this Application, Columbia is proposing to continue its capital expenditure program approved in Case Nos. 11-5351-GA-UNC et al. in 2013 and succeeding years, up until the point where the accrued deferrals, if included in rates, would cause the rates charged to Columbia's SGS customers to increases by more than $1.50/month as authorized in Case Nos.. 11-5351-GA-UNC et al.
4) During the period January 1, 2013 through December 31, 2013 Columbia estimates its capital expenditure program will include an investment level of approximately seventy-two million dollars of net plant investment that qualifies for the accounting treatment under Rev. Code 4929.111(A)
5) Pursuant to Rev Code 4929.111 (B) Columbia includes as Attachment A hereto its estimated total cost of the capital expenditure program covered by this application with treatment described more fully hereinafter. The actual expenditures will vary by category. The total amount expended could also vary due to Columbia's management of its capital expenditures budget in the aggregate, rather than by individual categories, and due to the development of Columbia's capital expenditure budget based upon cash payments (Account 107) rather than the date plant becomes used and useful and transferred to plant in service (Account 101, gas Plant in Service). This timing difference between the date cash payments are made and the date plant is placed into service will result in the total capital budget estimates detailed on Attachment A being different in a given year with a corresponding increase or decrease in the actual expenditures eligible for accounting treatment under Rev. Code 4929.111(B)
6) Columbia will include in its annual informational filing, on or before April 30 each year, all of the above-referenced information required by the Commission in its Findings and Order, including its projected capital expenditures budget for the current and next calendar year in a similar format as shown in Attachment A hereto.
7) Columbia proposes the use of the projected CEP investment for the current and next calendar year included in its Annual CEP Report to be filed on or before April 30 each year be the maximum allowable level of investment eligible for deferral in accordance with Rev. Code 4929.111(B)
8) Columbia's capital allocation policy governs the allocation of capital, including the identification and prioritization of capital projects. The annual capital budget allocation approved by the NiSource Board of Directors is consistent with Columbia's obligation to furnish necessary and adequate services and facilities under Rev. Code 4905.22. the following components are included in Columbia's capital expenditures program:
    a. Replacement/Public Improvement/Betterment – Replacement of facilities for any of the following reasons: (1) physical deterioration; (2) meeting the requirements of governmental authorities related to street and highway construction; (3) accommodating existing customer requests for facility relocation; and (4) improving system operating conditions and ensuring adequate distribution system capacity and/or system reliability. This Replacement/Betterment category may

include, but is not limited to, cost related for installation of and/or improvements to mains and service lines, measuring and regulation stations, district regulatory stations, excess pressure measuring stations, meters, meter sets, AMR devices, house regulators, and any associated buildings, land or land rights.

b. Growth – Facilities required to provide service to new customers or to provide increased load capacity to existing customers. The category may include, but is not limited to, costs associated with the installation of and/or improvement to mains and services (including service line installations to new customers served by existing mains), district regulator stations, excess pressure measuring stations, meters, meter sets, AMR devices, house regulators, and any associated buildings, land or land rights.
c. Support Services – Capital expenditures that are not directly related to gas facilities fall into this category which may include, but is not limited to, costs associated with the purchase of and/or improvements to buildings and structures (including associated land and land rights), environmental remediation at company owned facilities, office furniture and equipment, motorized equipment and trailers, power operated equipment, and other miscellaneous equipment.
d. Information Technology – Capital expenditures related to technology and communications infrastructure. This category may include, but is not limited to, costs associated with purchase and installation of communications equipment (including associated buildings, land or land rights), data processing equipment, data processing software, and software licenses.

9) For all categories described above the costs include (where applicable) Supervisory, Engineering, General, and Administrative overheads, and an Allowance for Funds Used During Construction, and are net of any contributions, deposits, or other aid to construction. None of the capital expenditure in the categories described above include costs targeted for inclusion in Columbia's Infrastructure Replacement Program or CHOICE/SSO Reconciliation Rider.
10) Columbia adheres to the FERC unified System of Accounts prescribed for Natural Gas Companies and Generally Accepted Accounting Principles when accounting for the actual cost of capital projects. Pursuant to the FERC Unified System of Accounts, all amounts included are just and reasonable. Projects that are deemed "used and useful" in serving the needs of Columbia's customers are reported as in-service. Detailed gas plant accounting records are maintained to permit identification, analysis and verification of capitalized costs.
11) Rev. Code 4929.111(A) authorizes a natural gas company to request approval of a capital expenditure program under Rev. Code sections 4909.18, 4929.05 or 4929.11 to implement a capital expenditure program for any of the following:
    a. Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program;
    b. Any program to install, upgrade, or replace information technology systems;
    c. Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.
12) Rev Code 4929.111(C) provides for the Commission's approval of a capital expenditure program if the Commission finds the natural gas company's capital expenditure program is consistent with the company's obligations to furnish necessary and adequate services and facilities under Section Rev Code 4905.22.

13) Pursuant to Rev Code 4929.111(D) the Commission shall authorize a natural gas company to defer or recover in an application filed under Rev Code 4929.111 the following:
    a. A regulatory asset for post-in-service carrying costs on that portion of the capital expenditure program assets that are placed in service but not reflected in rates as plant in service;
    b. A regulatory asset for the incremental depreciation on that portion of the assets of the capital expenditure program that are placed in service but not reflected in rates as plant in service; and,
    c. A regulatory asset for the incremental property taxes directly attributable to the assets of the capital expenditure program that are placed in service but not reflected in rates as plant in service.
14) Rev Code 4929.111(F) authorizes a natural gas company to make any accounting accruals necessary to establish the regulatory assets authorized under Rev Code 4929.111(D), in addition to any allowances for funds used during construction. Pursuant to Rev Code 4929.111(G) any accrual or deferral for recovery shall be calculated in accordance with the system of accounts established by the Commission under Rev Code 4905.13.
15) The Finding and Order in Case Nos. 11-5351-GA-UNC et al. authorized the following accounting for Columbia's calculation and total monthly deferral of regulatory assets for that portion of the capital expenditure program assets that are placed in service but not reflected in rate as plant in service.

    Total Monthly Deferral = (PISCC) + (Depreciation Expense) + (Property Tax Expense) – (Incremental Revenues

    Where:

    PISCC = [(Previous Month's Cumulative Gross Plant Additions) – (Previous Month's Accumulated Depreciation) – (Previous Month's Cumulative Retirements) + (1/2 Current Month's Plant Additions) – (1/2 current Month's Retirements)] * [(Depreciation Rate) / (12 Months)]

    Property Tax Expense = [(Previous Year End Cumulative Gross Plant Additions) – (Previous Year End Cumulative Retirement)] * (Percent Good Adjustment) * [(Effective Property Tax Rate) / (12 Months)]

    Incremental Revenue = [(current Month's Customers – Baseline Customers) * (Cost Portion of Rate)] + [(Consumption by non-SFV customers directly attributable to program investment) * (Cost Portion of Rate)] + (Other revenues directly attributable to program investment)

16) Pursuant to Rev Code 4929.111 (A-F) Columbia hereby requests continuation of its capital expenditure program and authority to defer related carrying costs, depreciation expense and property tax expense up until the time these deferrals equate to a $1.50/month charge to SGS customers if included in rates. Specifically, Columbia requests to be permitted to compute and defer these costs in accordance the Commission's Findings and Order issued in Case Nos. 11-5351-GA-UNC et al.
17) The treatment requested in this Application is consistent with that recommended by Staff and approved by Commission in Case Nos. 11-5351-GA-UNC et al. for the period October 1, 2011 to December 31, 2012.
18) In this Application Columbia is requesting continued authority to defer the aforementioned expenses through the use of the accounting authority and formulas described above.

Columbia is not requesting recovery of any of the deferred amounts as part of this Application. Recovery of any amounts deferred pursuant to approval of this Application will be addressed in a separate proceeding.

19) This Application will not result in an increase in any rate, joint rate, toll, classification, charge or rental. Therefore, this Application is an application not for an increase in rates under Rev. Code 4909.18

Case No. 17-2202-GA-ALT – Capital Expenditure Program Rider

On April 2, 2018, Columbia Gas issued its application in regard to the Capital Expenditure Program Rider (CEP Rider)

On page 1 through 4 of the application: Pursuant to Revised Code §§ 4929.111, 4929.05, and 4909.18, Columbia Gas of Ohio, Inc. ("Columbia") filed its Application in this docket on December 1, 2017, in which it requested authority to implement a new alternative rate plan to establish a capital expenditure program rider ("CEP Rider"). The purpose of the CEP Rider is to recover the post-in-service carrying costs, incremental depreciation expense, and property tax expense currently deferred pursuant to Columbia's capital expenditure program deferral ("CEP Deferral"), as well as the corresponding assets to which these expenses are directly attributable in the capital expenditure program. Columbia now submits this Amended Application to be effective as of December 1, 2017, pursuant to Staff correspondence dated March 19, 2018, filed in this proceeding.

The information required by Ohio Adm. Code 4901:1-19-06(C) is attached in the following exhibits:

- Exhibit A: Alternative Rate Plan
- Exhibit B: Authorized Exempted Services
- Exhibit C: Discussion Regarding Cross-Subsidization of Services
- Exhibit D: Discussion Regarding Compliance with Revised Code §§ 4905.35 and 4929.02
- Exhibit E: List of Witnesses Sponsoring Application Exhibits
- Exhibit F: Current, Redline Proposed, and Clean Proposed Tariff Sheets
- Exhibit G: Typical Bill Comparison
- Exhibit H: Statutory Schedules – R.C. §§ 4909.18(A) – (D)1
- Exhibit I: Section A and B Schedules of Standard Filing Requirements pursuant to Ohio Adm. Code 4901-7-01
- Exhibit J: Additional Schedules Supporting the Application
- Exhibit K: Proposed Newspaper Notice pursuant to R.C. § 4909.19 and Ohio Adm. Code 4901-7-01, Appendix A, Chapter II (B)(7)

Columbia is filing additional testimony in support of this Amended Application contemporaneous with this Amended Application.

3. Explanation of the Plan's Justness and Reasonableness

Columbia's proposed alternative rate plan to establish a CEP Rider is just and reasonable. By beginning a gradual recovery of the CEP Deferral and underlying assets in 2018, Columbia will request less than if it were to continue deferring expenses until the deferral reaches the SGS Class rate impact threshold established in Case Nos. 11-5351-GA-UNC, et al., and continued by Case Nos. 12-3221-GAUNC, et al. This is because Columbia will stop deferring additional post-in-service Rider. Additionally, including recovery on and of the underlying investments to which the CEP Deferral relates will obviate the need to continue to defer future expenses associated with those investments. Because customers would save money by allowing Columbia to begin gradually recovering its CEP Deferral and the underlying related investments in 2018, Columbia believes its CEP Rider is just and reasonable.

4. Proposed Procedural Schedule

Columbia is committed to supporting an expedited review and settlement process with this Amended Application. As such, Columbia proposes the following procedural schedule in this proceeding:

- Final Third-Party Audit Issued
- Staff Report Issued 7 days after the Final Third-Party Audit Issued
- Discovery/Intervention Deadline 14 days after the Staff Report Issued
- Objections/Testimony due 30 days after the Staff Report Issued
- Evidentiary Hearing begins 7 days after Objections are filed
- Initial Brief is due 7 days after Evidentiary Hearing concludes
- Reply Brief is due 10 days thereafter

7. Conclusion

For the reasons provided in this Amended Application, Columbia respectfully requests that the Commission establish a CEP Rider, pursuant to the terms outlined herein, and grant any other necessary and proper relief.

On page 1 through 3 of Staff's Review and Recommendation:

BACKGROUND:

In accordance with R.C. §§ 4929.111,4929.05,4929.051(A), and 4929.11, on December 1,2017 Columbia Gas of Ohio (Columbia or Company) filed an application (Application) with the Public Utilities Commission of Ohio (Commission) for authority to establish a capital expenditure program rider (CEP Rider). Columbia seeks to recover the post in-service carrying costs (PISCC) and incremental deprecation and property tax expenses currently deferred under the Company's capital expenditure program deferral (CEP Deferral) and a return-of and return-on the underlying CEP assets. On March 19, 2018, Commission Staff, pursuant to Commission Rule 4901:1-19-07 (A)(l), informed Columbia of Staffs determination that its Application was for an increase in rates and, as such, should be amended to include all information described in division (A) through (D) of R.C. §4909.18 and the standard filing requirements described in O.A.C. Rule 4901-7-01 (SFRs). Alternatively, Staff informed Columbia that it could withdraw its Application or seek waivers of the additional filing requirements. On April 2,2018, Columbia filed an amended application for a CEP Rider (Amended Application), a waiver motion for some of the R.C. §4909.18 requirements and SFRs, and a memorandum in support of its waiver request. Staff has reviewed Columbia's Motion for Waivers (Motion) and related supporting memorandum and offers the responses and recommendations set forth below.

COLUMBIA'S MOTION FOR WAIVERS AND MEMORANDUM IN SUPPORT

In its motion, Columbia takes the opportunity to notify the Commission that the test year for the CEP Rider pursuant to the Amended Application is the twelve months ending December 31, 2017 and the date certain is December 31, 2017. The Company also requests that the Commission waive all SFR filing requirements except for Sections A and B and the newspaper notice contained in the Chapter 11(B)(7). Columbia maintains that information being sought in the SFRs subject to waiver is not necessary for Staff to effectively and efficiently review the Amended Application. In the Memorandum in Support, the Company specifically delineates the filing requirements that it is seeking to be waived and characterizes each as unnecessary because the information requested or notice required has already been supplied or made, not necessary because the information provided with the Amended Application is sufficient to enable the Staff to efficiently and effectively conduct its investigation, or unnecessary because the information being sought relates to rate increases being sought in a base rate case, which is not applicable

STAFF'S RESPONSE AND RECOMMENDATIONS

Staff has reviewed Columbia's Amended Application, Motion for Waivers, and Memorandum in Support. Staff agrees that the Amended Application provides sufficient information for the Staff to conduct its investigation. Therefore, Staff does not object to the Commission waiving the SFR requirements specified in the Company's Memorandum in Support. However, the Staff does not agree to Columbia's characterization that the information being sought in the filing requirements subject to waiver is not necessary for the Staff to conduct its investigation in this case. Some information being sought may indeed relate exclusively to projections of base rates or other future projections or otherwise seek information that later proves unnecessary, but Staff is not willing to concede at this early stage of investigation that all possible future projections or information being sought in the filing requirements subject to waiver is not necessary. Staff is agreeable to the Commission granting Columbia's Motion for Waiver only on the condition that Columbia must furnish all information that Staff deems necessary to complete its investigation upon request from the Staff. Furthermore, Columbia requests that CEP Rider rates be effective on August 1, 2018. Given such an aggressive timeline. Staff would request that the Commission direct Columbia to respond to Staff formal information requests within five business days, unless the Company requests additional time due to complexity or availability concerns or Staff requests a shorter timeframe because information is readily available. Therefore, Staff recommends that the Commission approve Columbia's Motion for Waivers without accepting the Company's characterizations that the information in the filing requirements subject to waiver is unnecessary and direct the Company to respond to Staff formal information requests as described above.

APPENDIX B: DATA REQUESTS AND INFORMATION PROVIDED

Set 1 – Submitted on May 15, 2018

1-1. **IRP vs. Non-IRP CEP Projects:**

Per the December 3, 2008, Order in Case No. 08-72-GA-AIR, IRP Projects include

a) The future maintenance, repair and replacement of customer-owned service lines that have been determined by Columbia to present an existing or probable hazard to persons and property, and the systematic replacement, over a period of approximately three years, of certain risers prone to failure if not properly assembled and installed. The replacement of customer-owned service lines and prone-to-failure risers was previously approved by the Commission in its opinion and order dated April 9, 2008, in Case No. 07-478-GAUNC;

b) The replacement of cast iron, wrought iron, unprotected coated steel, and bare steel pipe in Columbia's distribution system, as well as Columbia's replacement of company-owned and customer-owned metallic service lines identified by Columbia during the replacement of all the above types of pipe (referred to as the Accelerated Mains Replacement Program or AMRP); and

c) The installation, over approximately a five-year period, of Automatic Meter Reading Devices ("AMRD") on all residential and commercial meters served by Columbia.

Per the October 3, 2011 Order in Case No. 11-5351-GA-UNC, CEP includes any infrastructure expansion, infrastructure improvement, or infrastructure replacement program; (b) any program to install, upgrade, or replace information technology systems; (c) any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.

Per Columbia Gas Application in Case No. 11-5351-GA-UNC, the CEP includes the following components: (a) Replacement / Public Improvement / Betterment; (b) Acquisitions; (c) Growth; (d) Support Services; (e) Information Technology; (f) Distribution Integrity Management Plant Implementation.

a) Please provide an explanation of the difference between Non-IRP/ CEP projects and IRP.

b) How are Non-IRP / CEP projects distinguished from IRP projects in the work management system?

c) How are Non-IRP projects identified after placed in service in the plant account system?

d) To what FERC plant accounts are non-IRP projects assigned?

e) Are there Non-IRP projects that are not included in the CEP? If so, please explain.

1-2. **Organization**: Please provide a current organization chart of the Company.

1-3. **Organization**: Please provide contiguous information for the period from October 1, 2008, through December 31, 2017, for the following items:

a) Name of the person with responsibility for plant accounting

b) Duration the person held the position

c) Summary of the qualifications of the person

d) Whether the person is still with the Company, and if so, the person's current position

e) Changes in the number of personnel in the Plant Accounting department.

1-4. **Accounting:** Please provide a chart (code) of accounts as of December 31, 2017.

1-5. **Case No. 08-0072-GA-AIR B Schedules**: Please provide, in Excel format, the final approved B Schedules in Case No. 08-0072-GA-AIR. If the final approved B Schedules are not available, please provide the B Schedules, in Excel format, included in the Company's revised schedules that reflect the removal of cost of plant sold after date certain.

1-6. **Case No. 08-0072-GA-AIR B Schedules Roll-Forward Balances**: Please provide, in Excel format, the roll-forward balances by year from December 31, 2007, to December 31, 2017, by FERC plant account.

1-7. **Case No. 11-5351-GA-UNC and 12-3221-GA-UNC Annual Informational Filings**: Please provide copies of the Company's schedules included in the Company's Annual Informational Filings in Excel format for 2011–2017. Also provide any supporting schedules that support the balances included within the annual information filings (e.g., depreciation and property tax calculations).

1-8. **Case No. 12-3221-GA-UNC Annual Informational Filing:** Please provide updated schedules in Excel format in the 2017 filing replacing fourth quarter estimates with fourth quarter actuals.

1-9. **Work Orders:** Please provide in Microsoft Excel format a list of all Non-IRP CEP work orders put in service by year, starting October 1, 2008, <u>January 1, 2008</u>, through December 31, 2017. Please identify the work orders as either IRP or CEP. For each work order, please include the following information for each year:

a) Plant accounts charged (FERC 300 accounts)
b) Project identification numbers (work order and project roll up, if applicable)
c) Project description. Single line description will be acceptable along with location numbers
d) Project Description (e.g., Replacement & Betterment, Growth, Support Services, Information Technology, etc.)
e) Work Order Construction Complete <u>Date</u> (when project became used and useful)
f) Work Order Accounting In-Service Date
g) Unitization Date
h) Dollar amount by FERC 300 account number
i) Whether the work was an addition or replacement
j) Whether the work order was a blanket project work order and, if so, associated project identification numbers

1-10. **Work Orders**: For each year that the lists of work orders are provided in Request #9, please provide a reconciliation of the work order total to the totals in the annual report of utility plant in service filed with the PUCO. For any differences, provide an explanation.

1-11. **Work Order Number**: Please provide an explanation of the digits included within the work order number as discussed during the kick-off meeting on May 15, 2018.

1-12. **Major Additions or Replacements**: Please provide a list with a description and total dollar amount of any <u>major</u> CEP additions and/or replacements placed in service during 2011 through 2017.

1-13. **Timeline**:

a) Please provide a timeline of major events that occurred since October 1, 2008, that had an impact on the plant-in-service balances. Examples of major events include, among other such events, major sales of assets, acquisitions, mergers, system conversions, and upgrades.

b) Please provide an explanation of each event and how the event affected plant balances.

c) Please provide an explanation of what steps were taken to ensure that plant balances were accurate following the impact of the event.

1-14. **Policies and Procedures**: Please provide the current policies and procedures and flowcharts for the following activities that provide input to distribution plant:

a) Plant Accounting:

i) Capitalization vs. Expense
ii) Preparation and approval of work orders
iii) Recording of CWIP, including the systems that feed the CWIP trial balance;
iv) Application of AFUDC
v) Recording and closing of additions, retirements, cost of removal and salvage to plant
vi) Unitization process based on the retirement unit catalog

vii) Application of depreciation
viii) Contributions in Aid of Construction (CIAC)
ix) Damage Claims

b) Purchasing/Procurement
c) Accounts Payable/Disbursements
d) Accounting/Journal Entries
e) Payroll (direct charged and allocated)
f) Insurance recovery
g) Allocations
h) Work Management System
i) Information Technology
j) Capital Project selection and prioritization
k) System planning and load growth

1-15. **Work Order Accounting:** Please provide a narrative of the CEP accounting with examples of how the following items take place:

a) A completed project is designated as CEP
b) The accounting entry or entries to record the deferral of a CEP project.
c) The accounting entry or entries to record the retirements of a CEP project.
d) The accounting entry or entries to record the retirement of a non-CEP project, where the replacement is a CEP project.
e) The accounting entry or entries to record PISCC, depreciation on the closed assets, and incremental property taxes.
f) The accounting entries to retire a CEP project.
g) How CEP deferred projects are unitized

1-16. **Work Order Accounting.** Please explain in detail how the deferred CEP assets are moved to utility plant in service once the proper deferral has been established. Include the following treatments:

a) How the proper reserve balance is determined. Adjusting the depreciation reserve based on using a composite rate of depreciation vs. a 300-account-based depreciation rate
b) How the assets are identified and categorized by FERC 300 account
c) How retirements are identified and charged to the proper 300 account reserve

1-17. **Policies and Procedures**: Please specifically explain any major changes that have been made to the Company's capitalization policy from October 1, 2008, through December 31, 2017.

1-18. **Unit of Property Catalog**:

d) Does the Company maintain a unit of property catalog for distribution assets?
e) If yes, how frequently is the catalog updated?
f) If not, why not?

1-19. **Systems**: from October 1, 2008 through December 31, 2017.

g) What system has the Company used to record entries to the General Ledger?
h) What system has the Company used to record assets to and from Utility Plant?
i) What system has the Company used to maintain the detail for the FERC 300 accounts?

1-20. **Approval Signatures**: Please provide the Level of Signature Authority (LOSA) document(s) that supports the approval of capital projects from October 1, 2008, through December 31, 2017.

1-21. **Depreciation:** Reference Schedule B-3.2.

j) Have depreciation rates been changed since the Commission's approval in Case No. 08-72-GA-AIR?
k) If depreciation rates have been changed, please explain for each change, when the change was made, what the change was, and whether it was approved by the Commission.
l) If a composite depreciation rate has been used in the CEP Informational Filings, please provide the rate used each year from 2011 through 2017 and how it was calculated.

1-22. **Property Taxes**: Please provide the property tax rate used in the CEP Informational Filings for each year from 2011 through 2017 and the workpapers showing how the rate was calculated.

1-23. **Allocations:** Please provide the allocation factors used to allocate plant for the last ten years.

1-24. **FERC Audits**: Please provide a copy of all FERC audit reports, if any, that were issued during the period October 1, 2008, through December 31, 2017. Also provide the Company's response to any findings and the ultimate resolution of those findings.

1-25. **Internal Audits**: Please provide a list of internal audits performed from October 1, 2008, through December 31, 2017. List the name of the audit, scope, objective, and when the work was performed.

1-26. **SOX Compliance Audits**: For any feeder system that feeds CWIP, please provide any SOX Compliance audits performed from October 1, 2008 (or the date Sarbanes Oxley was implemented by the Company if after October 1, 2008), through December 31, 2017. Include whether the controls passed or failed and, if failed, the severity and impact of the failure. NOTE: 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 plant balances.

1-27. **Unitization Backlog**: Please provide information regarding any backlog in the unitization of distribution work orders as of December 31, 2017. Please provide the number of backlogged work orders, the dollar values of each, and the length of time for each in months (e.g., under three months, four to 12 months, and over 12 months). If possible, provide the list for both CEP work orders and non-CEP work orders.

1-28. **AFUDC**: Please provide the AFUDC interest rate for each year from October 1, 2008, to December 31, 2017.

1-29. **Insurance Recovery**:

m) Has there been any significant event in the last ten years that resulted in an insurance claim recovery greater than $50,000 related to Distribution Plant? If so, please provide a list of such events, how each recovery was recorded to the Company's books, and how it was reflected in plant balances.

n) Are there any pending Distribution plant insurance claim recoveries as of December 31, 2017, that are not recorded or accrued that would be charged to capital? Please provide the type of recovery, estimated amount, and when receipt is expected.

1-30. **Tax Cuts and Jobs Act (TCJA)**: How has the TCJA effect been reflected in the Company's Non-IRP CEP recovery?

1-31. **Cost per Mile:** For the CEP Projects with the Description "Replacement & Betterment" for each of years 2011-2017, please provide the total main miles replaced/installed and the average cost per mile with and without accounting overheads.

1-32. **Cost per Mile:** For the CEP Projects with the Description "Growth" for each of the years 2011-2017, please provide the total main miles replaced/installed and the average cost per mile with and without accounting overheads.

1-33. **Commission Annual Reports:** Please provide the Annual Report for the year ending December 31, 2107 filed with the Commission when it is available.

Set 2 – Submitted on June 6, 2018

2-1. **Follow-up to Response to DR 1-010:**

Please respond to the following questions regarding the Reconciliation of IRP & CEP to Annual Report provided in response to DR 1-010:

a) In the response to DR 1-009, two attachment spreadsheets were provided giving all CEP work orders by year. Attachment A provides CEP additions. These totals match to line 12 of the spreadsheet reconciliation response to DR 1-010. However, the totals by year of the retirements in DR 1-009, Attachment B, do not match to line 13 of the spreadsheet reconciliation response to DR 1-010.

i) Please verify that the difference in the retirement totals (between line 13 of DR 1-010 and the totals of DR 1-009, Attachment B) are due to prior year (non-CEP) plant retirements included in DR 1-009 Attachment B.

ii) Please identify the work orders in the DR 1-009, Attachment B (retirements), response that are exclusively CEP (and not merely non-IRP from years prior to implementation of the CEP).

b) In the spreadsheet reconciliation response to DR 1-010, lines 16 through 22 list non-IRP and non-CEP items that are incorporated into the net change in plant in service. Please provide detailed explanations for each of these items, including reasons for not including them in the CEP.

2-2. **CEP Schedules:** Reference Case No. 17-2202-GA-ALT Amended Application and Data Request 1-8. Request 1-8 asked that the 2017 Annual Information Filing fourth quarter be updated with actual amounts. The response was that the fourth quarter 2017 was estimates. If actual amounts are available, please update the schedules. If the Company is not able to update the schedules, please explain why.

2-3. **CEP Schedules:** Follow up to Data Request 1-7. Please confirm that the 2013 through 2017 balances reflect actual amounts. If not, please provide the actual amounts through 12/31/2017.

2-4. Follow-up to Data Request response BRCS DR Set 1-25 Attachment A—**Audits**. Please provide the summary findings and recommendations for the following audits:

a) Tab COH Only:
   i) COH Infrastructure Replacement Program—report issued 10/3/2013
   ii) COH Tracker Review—report issued 03/14/2011
   iii) COH AMRP/CSL Program Tracker Audit—report issued 12/18/2009
b) Tab COH Included:
   i) Columbia Companies Earned Value Metric Reporting & Calculation Review—report issued 02/16/2017
   ii) Infrasource Contract Compliance Audit (NIPSCO & Columbia)—report issued 02/16/2017
   iii) Preliminary Survey Cost Review (NGD)—report issued 3/26/2015.
   iv) NiSource Corporate Services Company Cost Allocation Audit—report issued
   v) Accounts Payable Field Process Review (NGD)—report issued 09/23/2013
   vi) NiSource Corporate Services Company Cost Allocation Audit—report issued 07/11/2013
   vii) Priority Pipe Replacement Program Review – CDC—r eport issued 07/28/2011
   viii) NGD Regulatory Orders - Change Management Process Review—report issued 01/27/2011
   ix) Capital Allocation Audit - NiSource Gas Distribution Companies—report issued 05/24/2010
c) Tab Corporate:
   i) NiSource Corporate Services Company Cost Allocation Audit—report issued 04/16/2018
   ii) NiSource Corporate Services Allocation Audit (NCSC)—report issued 05/18/2017
   iii) NiSource Corporate Services Cost Allocation (NCS)—report issued 08/21/2014
   iv) Accounts Payable Duplicate Payment Review—report issued 03/17/2014
   v) NiSource Corporate Services Company Cost Allocation Audit—report issued 07/11/2013
   vi) Significant Account Review (NGD)—report issued 02/06/2013
   vii) NCSC Cost Allocation Audit—report issued 07/12/2011
   viii) NGD Monthly Close Process—report issued 06/14/2011
   ix) NiSource Corporate Services Allocation Audit (NCSC)—report issued 07/21/2010
   x) Accounts Payable Audit—report issued 02/08/2010
   xi) NiSource Corporate Services Allocation Audit (NCSC)—report issued 07/17/2009

2-5. Follow-up to Data Request response BRCS DR Set 1-2 Attachment A—**Organization Chart**. As a result of a telephone conversation with the Company, they provided an organization chart that included those positions and individuals that were relevant to the scope of our audit. As a result of our review, we determined that several people may have the same job title, and therefore, we were unable to select individuals to interview. Please provide a list of personnel, at a Supervisory level or above, with working knowledge of the specific subject matter, to discuss the following topics. Please include job titles that can be tracked back to the organization chart. For expediency, please feel free to combine subjects to reduce the number of interviews.

a) Major events within Columbia Gas from 2008 through 2017
b) Functions and history of Plant Accounting
c) Work order allocations, including process and policies to ensure proper classification of assets as either IRP or CEP
d) CEP deferral
e) Retirement Ratio used in CEP
f) PISCC used in the CEP
g) Property taxes used in the CEP
h) Recording of revenue offset to the CEP deferral
i) AFUDC
j) IT
k) WMS
l) Engineering project Planning, including project selection (reliability and load) along with project prioritization methodologies
m) Rates and regulatory (CEP compliance)
n) Capital budgeting, including historical and future plans
o) Work force and project management (in-house and contractors), metrics, and scorecards used
p) Work order development and cost estimating work sheets
q) Asset record repository—use of GIS, detail, and accuracy.

2-6. Follow-up to Data Request response BRCS DR Set 1-27 Attachment A—**Unitization Backlog**.

a) Column F—Please confirm that the in-service date is the date the assets are ready for service and are moved from CWIP (FERC 107) to CCNC (FERC 106).
b) Column G—Does the completion date represent the date that the project is 100% complete and ready to be unitized? If not, please define what completion date is.
c) Column H—What does the close date represent?
d) Column J—Does the length of time represent the difference between Column G and 12/31/17? If not, please explain what it does represent.
e) Column I—Does this column represent the remaining project dollars in FERC 106 as of 12/31/17? If not, please explain what it does represent.
f) Please confirm that as of 12/31/17, the dollars represented in Attachment A are not unitized.
g) Are the CEP project dollars moved to the Deferral at the in-service date? If not, when?

2-7. Follow-up to Data Request response BRCS Set 1-26 Attachment A—SOX Compliance Audits, columns G and I. For the SOX audits in which the controls were determined to be inadequate (Col G) and the test conclusion failed (Col I), please provide a summary of any significant control deficiencies, along with how those deficiencies were corrected and /or mitigated.

Set 3 – Submitted on June 13, 2018

3-1. For the years 2008-2017, please complete the following table for Main Miles Replaced

	CEP Related			
Year	**Costs attributed to Main Replacement (A)**	**Miles of Main Replaced/installed new (B)**	**Sum of Total Main Miles per PHMSA Annual filing**	**Cost per Main Mile replaced (A/B)**
2008				
2009				

2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				

	NON -CEP Related			
Year	**Costs attributed to Main Replacement (A)**	**Miles of Main Replaced/installed new (B)**	**Sum of Total Main Miles per PHMSA Annual filing**	**Cost per Main Mile replaced (A/B)**
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				

3-2. For the years 2008-2017, please provide complete the following table for # of Services Replaced

	CEP Related			
Year	**Costs attributed to Service Replacement (A)**	**# of Services Replaced/installed new (B)**	**Sum of Total # of Services per PHMSA Annual filing**	**Cost per Service replaced (A/B)**
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				

	NON -CEP Related

Year	Costs attributed to Service Replacement (A)	# of Services Replaced/installed new (B)	Sum of Total # of Services per PHMSA Annual filing	Cost per Service replaced (A/B)
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				

3-3. In reference to Columbia Gas Ohio Response to DR set 1-32, please confirm if the cost per mile of main pipe calculation for CEP "Growth" projects was calculated reflecting only Mains related work orders.

3-4. In reference to Columbia Gas Ohio response to DR set 1-11, part (e), please provide the following information

Described in DR set -11, (e) Condensed Operating Location number code (from WMS job order #)	Operating Location (e.g. Columbus Toledo, East Liverpool, etc.)	Region (e.g. Central, North Eastern, etc.)

3-5. In reference to DR set 1-9 Revised Attachment A, Work Order details, please provide the following information for the CEP category of "Growth"

CEP budget Category of Growth

Year	# of Services Installed to provide service to new customers	Number of Services replaced to provide increased load capacity	Total # of Services installed/ Replaced
2011			
2012			
2013			
2014			

2015			
2016			
2017			

CEP budget Category of Growth

Year	Miles of Main Installed to provide service to new customers	Miles of Main replaced to provide increased load capacity	Total Miles of Main installed/Replaced
2011			
2012			
2013			
2014			
2015			
2016			
2017			

3-6. Please provide Columbia Gas Ohio's most recent CapEx project selection and prioritize policy and procedures

3-7. Please provide Columbia Gas Ohio's most recent policy and planning procedures that describe when a service or main should be upgraded due to load growth

3-8. In reference to Columbia Gas Ohio's response to DR set 1-31, cost per mile for CEP projects with the description "Replacement & Betterment"; please elaborate on the key drivers of year to year average cost per mile fluctuations.

3-9. Follow up to Data Request response BRCS DR 2-4, attachment a. The audit reports listed below had findings and recommendations. Please indicate how and when the recommendations were implemented. If not implemented, please explain why.

a. COH Tracker Review – Report issued 3/14/2011
b. COH AMRP/CSL Program Tracker Audit – Report issued 12/18/2009
c. Columbia Companies Earned Value Metric Reporting & Calculation Review – report issued 2/16/2017.
d. Infrastructure Contract Compliance Audit (NIPSCO & Columbia) –Report issued 2/16/2017.
e. Preliminary Survey Cost Review (NCD). – Report issued 3/26/2015.
f. Accounts Payable Field Process Review (NGD) – Report issued 9/23/2013.
g. Priority Pipe Replacement Program Review – CDC-r- Report issued 7/28/2011.
h. NGD Regulatory Orders – Change Management Process Review – report issued 1/27/2011.
i. Accounts Payable Duplicate Payment Review – Report issued 3/17/2014.
j. Significant Account Review (NGD) – Report issued 2/6/2013.
k. Accounts Payable Audit –Report issued 2/8/2010.

<u>Set 4 – Submitted on June 14, 2018</u>

4-1. Reference Company response to BRCS-DR-Set 1.9 Attachment A REVISED. Please refer to the attached "Set 4 - Sample Selection CEP and NON-CEP.xlsx" work orders selected from the population of work orders provided in response to the referenced data request. Please note that the selection is work order/project/programs (hereafter referred to as "work orders"). For each work order on the list, please provide the following information in sortable Microsoft Excel spreadsheets:

a. Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).
b. Work order justification and approval at the highest approval level available based on the nature of the work order.
c. Estimated in-service date and actual in-service date.
d. For non-blanket work orders, and blanket work orders where the specific blanket work orders can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%. .
e. Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses.
f. Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

Notes:

- Please send a sample of the detail that will be provided to make sure it is what we need.
- If you have any questions, please contact Joe Freedman directly at 607-280-3737 or Jfreedman@blueridgecs.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

Set 5 – Submitted on June 18, 2018

5-1. Variance Analysis: Blue Ridge compared DR response 1-6, Attachment A, tab WPB-2.3, to Columbia Gas's Natural Gas Companies Annual Reports to PUCO for years 2008 through 2017. The ending balances for each year for the Distribution Accounts (30100 through 39800) in the workpaper matched to the Annual Reports in the majority (131 of 216) of cases. However, 85 balances, listed in the attached spreadsheet (WP Variance Sch B2.3 to PUCO Annual Report.xlsx), did not match. Please provide a reconciliation for these mismatching account balances.

Set 6 – Submitted on June 25, 2018

6-1. **Overhead and Indirect Costs**: Please provide a list of all overheads (labor loadings, etc.) and any other indirect items charged to Columbia Gas work orders, including descriptions both of the type of charge and how that charged item is applied (e.g., calculation with descriptions of factors used in the calculations).

6-2. **Allocations**: Follow-up to DR 1-23. In its response, the Company stated that 100% of Columbia's investment is jurisdictional. To clarify, please verify that none of the 300 series accounts, including intangible plant (e.g., IT software) and general plant, includes items shared or charges applied from parent, shared services, or sister organizations within the NiSource family.

6-3. **Variance Analysis:** Follow-up to response to DR 1-6 Attachment A, tab WPB2.3. Certain changes in plant accounts include such anomalous items as retirements greater than additions, large addition or retirements increases over the previous year, large transfers/adjustments, etc. Please provide detailed explanations for the items listed in the attached pdf file titled "Var Analysis Attachment 1.doc."

6-4. **Composite Depreciation Rates**: Follow-up to the Plant Accounting interview conducted on June 22, 2018. Please provide the detailed calculation, along with supporting work papers, for the composite depreciation rate used for the CEP by year from 2011 through 2017.

6-5. **Depreciation Accrual Rates**: Please provide the most recent Commission-approved depreciation accrual rates by FERC account (including any subaccounts).

6-6. **Subaccounts**: Please provide a list of the FERC 300 subaccounts and descriptions used by the Company.

6-7. **Subaccounts**: Has the Company added any additional FERC 300 accounts and/or subaccounts that were not included in the most recent Commission-approved depreciation accrual rates?

6-8.CEP Accumulated Depreciation: Please supply rolled-forward gross plant by FERC account number by month from the inception of the CEP deferral through 12/31/2018 for all CEP projects.

6-9. **AFUDC**: Follow-up to Plant Accounting interview conducted on January 22, 2018.

a) Please provide the interim and annual AFUDC rates and their supporting calculations for each year from 2008 through 2017.

b) Please explain how the AFUDC applied to capital work orders is adjusted for the change in the rate from interim to final.

c) Please explain specifically how the additions to plant that flow into the CEP are adjusted for the change in rates from interim to final.

Set 7 – Submitted on July 7, 2018

7-1. **Policies and Procedures:** Follow-up to DR 1-14. In the response to DR 1-14, the Company stated that the following areas had no current corporate policy: (1) preparation and approval of work orders, (2) damage claims, (3) accounting/journal entries, and (4) allocations. Please provide any documentation that governs how Company personnel are to perform those activities and/or the inclusion of those activities in other policies, procedures, or other guideline documentation.

7-2. **Policies and Procedures:** Follow-up to DR 1-18 and the June 22, 2018, Plant Accounting interview with Jeff Gore, Matt Ruth, and Nick Drew. Please verify the discussion impression that Unit of Property Catalog modifications are infrequent and typically would occur to address technological changes not addressed by the existing list of capital assets or to address a circumstance not previously identified.

7-3. **Internal Audits -** Follow up to Data Request response 2-4, attachment 1. For the attached Highlighted (YELLOW) internal audit reports please indicate if the audit recommendations were implemented, and if so how, and if not why not.

7-4. **FERC Audit -** Follow up to Data Request response 1-24. please indicate if the FERC audit recommendations were implemented, and if so how, and if not why not

7-5. Please provide an electronic copy of most recent Columbia of Ohio Gas Design and Construction Standards.

7-6. Please provide an electronic copy of the most current Columbia Gas of Ohio Distribution Integrity Management Program (DIMP).

7-7. For the years 2008–2017, please provide the following table of services "leaks cleared" ("leaks cleared" defined as both repaired and replaced).

Services	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Number of Leaks Cleared										
Miles in Service										
Services Leak Cleared per Mile										

7-8. For the years 2008–2017, please provide the following table of Main "leaks cleared" ("leaks cleared" defined as both repaired and replaced).

Main Leaks Cleared per Mile by Material Type	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Steel Unprotected Bare and Coated										
Total Leaks Cleared										
Miles in Service										
Leak Cleared per Mile										
Cast/Wrought Iron										
Total Leaks Cleared										
Miles in Service										
Leak Cleared per Mile										
Plastic										
Total Leaks Cleared										
Miles in Service										
Leak Cleared per Mile										
All Other Pipe not listed above										
Total Leaks Cleared										
Miles in Service										
Leak Cleared per Mile										
System Total										
Total Leaks Cleared										
Miles in Service										
Leak Cleared per Mile										

7-9. In reference to the continued demand for natural-gas-qualified construction crews and resources,

a) Please describe the impact of contractor costs on the annual cost per total main mile rate for each of the years 2008–2017, and
b) Please describe what process and initiatives are in place now and anticipated to manage contractor costs going forward.

7-10. Please provide the approximate percentage of contractor vs. in-house labor used for capital activities for years 2008 through 2017.

7-11. What analysis has been done to determine that the use of contractors is the least cost alternative and/or provides the greatest benefit to the ratepayer?

7-12. What steps has the Company taken since the inception of the CEP to contain costs?

7-13. Please provide a list of contractors, description of work performed, and amount paid that provided services for CEP work since the CEP inception.

7-14. Please provide a copy of the contracts for contractors since the inception of the CEP deferral.

7-15. How has the demand for Gas contractors in Ohio and surrounding states impacted the overall cost to complete capital work?

7-16. How has the Company address the demand constraints for gas contractors?

Set 8 – Submitted on July 18, 2018

8-1. **FIELD VISITS**: As a continuation of the audit process, we have selected certain work orders/projects, for field verification from the work order sample. The purpose of the field verification is to determine that the assets have been installed per the work order scope and description. The work order/project selection criteria were primarily assets that are representative of capital projects Columbia Gas of Ohio has included in the CEP and NON CEP.

Blue Ridge will conduct the verifications from the afternoon of Tuesday July 24, 2018, through Friday, July 27, 2018, with all days expected to be in the Columbus or Three Rivers areas.

The lists of the projects to be reviewed are included in Tables 1 and 2. To assist Blue Ridge in that endeavor, please provide, or have available, the following items:

a. An individual(s) who can coordinate all the field verification with Blue Ridge
b. Representatives from Columbia Gas of Ohio who can field assist Blue Ridge at each location
c. The Project Manager or a person who was responsible for the work on each project available to answer Blue Ridge's questions
d. Schematics/drawings or any other visual diagrams that indicate what was built or installed
e. A list of material and or equipment installed along with any applicable serial numbers
f. For Table 2 (below), work order information as follows: (Note: this information has already been provided for the projects in Table 1.)
    i. Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping)
    ii. Work order justification and approval at the highest approval level available based on the nature of the work order
    iii. Estimated in-service date and actual in-service date
    iv. For non-blanket work orders and blanket work orders, which can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%.
    v. Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses

vi. Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded

If Columbia Gas of Ohio has questions about the selection or any other requirement, please contact XXXXX via e-mail at XXXXX or by phone at XXXX or XXXX at XXXX or by phone at XXXX.

Work orders from Sample - No additional cost data or project detail required (previously provided in Set 4.1)

	Work Order	CEP/ Non-CEP	Day of Review	Location	Type of Review	Gas Plant Account	Budget Mapping	in service year	Total
1.	**9109.3411A034600**	CEP	7/24/18	Columbus Arena Building	Desktop/Walk-thru	various	Shared Services Allocation	10/1/14	$30,090,840
2.	**NCSE16DPRMC**	CEP	7/24/18	Columbia Arena Building	Desktop	30330	Shared Services Allocation	9/1/17	$349,897
3.	**0561.34160139991**	CEP	7/26/18	Columbus	Desktop	37600	Public Improvement	12/1/17	$701,219
4.	**8347.34130137197**	CEP	7/26/18	Columbus	Desktop & possible Field Audit	various	Growth	8/1/14	$534,713
5.	**9501.34150138531**	CEP	7/26/18	Columbus	Desktop & possible Field Audit	various	Acquisitions	12/1/15	$31,397,235
6.	**7265.34110146029**	Non-CEP	7/26/18	Muskingum Valley	Desktop	37625	Age & Condition	3/1/13	$1,575,357
7.	**0555.34120122190**	CEP	7/26/18	North Pointe	Desktop	37600	Growth/Betterment	3/1/14	$285,979
8.	**7119.34100121126**	Non-CEP	7/27/18	North Pointe	Desktop	37625	Mains Replacement/ Age & Condition	11/1/11	$1,012,058
9.	**7929.34080129187**	Non-CEP	7/27/18	North Pointe	Desktop	37625	Mains Replacement/ Age & Condition	6/1/11	$833,792
10.	**8103.34110121216**	Non-CEP	7/27/18	North Pointe	Desktop	37625	Age & Condition	11/1/11	$1,530,373
11.	**7799.34160062665**	Non-CEP	7/26/18	Springfield	Desktop	37625	Age & Condition	11/1/17	$1,256,332
12.	**7607.34150151789**	CEP	7/25/18	Three-Rivers	Desktop	37910	Betterment	10/1/16	$xxx
13.	**8655.34160152208**	CEP	7/25/18	Three-Rivers	Desktop & possible Field Audit	37600	Growth	12/1/17	$xxx
14.	**8341.34120151286**	Non-CEP	7/27/18	Three-Rivers	Desktop	37625	Age & Condition	11/1/14	$1,149,611
15.	**7411.34130116177**	Non-CEP	7/26/18	Toledo	Desktop	37625	Age & Condition	12/1/14	$6,842,003

Work orders - Additional cost data and project detail required (see item f above)

	Work Order	CEP/ Non-CEP	Day of Review	Location	Type of Review	Gas Plant Account	Budget Mapping	in service year	Total
16.	**0567.34D00342011**	CEP/Non-CEP	7/26/18	Columbus	Desktop	38100	Meters/Growth	1/1/11	CEP $1,000,887 Non-CEP $1,860,474
17.	**0567.34D00342014**	CEP	7/26/18	Columbus	Desktop	38100	Growth	1/1/17	$3,092,629
18.	**0549.34D00342008**	CEP/Non-CEP	7/26/18	Columbus	Desktop	38110	Growth/Auto Meter Reading Devices	1/1/17	CEP $2,687,010 Non-CEP $1,139,692
19.	**7607.34150151848**	CEP	7/25/18	Three-Rivers	Desktop	37600	Betterment/Growth	8/1/16	$xxx
20.	**8475.34140151696**	CEP	7/25/18	Three-Rivers	Desktop	37820	Growth	10/1/15	$600,688
21.	**8475.34150151827**	CEP	7/25/18	Three-Rivers	Desktop	38745	Growth	10/1/15	$473,134

22. 8655.34160152290	CEP	7/25/18	Three-Rivers	Desktop & possible Field Audit	37820	Growth	12/1/17	$xxx
23. 7785.34160152216	Non-CEP	7/25/18	Three-Rivers	Desktop & possible Field Audit	37625	Age & Condition	8/1/17	$919,905
24. 8759.34160152350	Non-CEP	7/25/18	Three-Rivers	Desktop & possible Field Audit	37525	Age & Condition	10/1/17	$895,657

Set 9 – Submitted on July 23, 2018

9-1. A NiSource document that approves the Columbia capital budget
9-2. A Columbia document that splits out the budget by Growth, Age & Condition, Public Improvement, Betterments, and Support Services that ties back to the overall NiSource approved capital budget
9-3. A Columbia document that splits the budget categories—Growth, Age & Condition, Public Improvement, Betterments, and Support Services—out by type of project type. Specifically, blanket projects vs. those projects considered specific-type projects based on how they were provided to Blue Ridge in the work order sample.
9-4. A variance analysis, cumulative by year, that shows budget by category, actual, variance, and explanation for variances over and under budget, if possible, broken down between blanket and specific projects
9-5. Earned value reports for 2016–2017 and an equivalent report for 2008–2015

Set 10 – Submitted on July 27, 2018

Follow up to Data Request Response 4-001—Work Order (Project) sample selection CEP and Non-CEP. CEP Specific and Non-CEP Work Orders (Projects)

10-1. Regarding work order 8347.34130137197 **-** Structure Minor Pl: 695400, the work order appears to include a SCADA building. Please explain how SCADA is considered Distribution.
10-2. For the following two work orders, please provide the supporting detail for the work performed.
   a. Work order 0563.34130106425 – Install 250' 4" Pmmp Csi –Fangboner Fre
   b. Work order 0565.34130062345 – 4" SI – London Correctional COR-Lon
10-3. The following three work orders were over budget by at least 20%. Please provide the level 2 approvals and support for the cost overrun. If the level 2 approvals are not appropriate, please explain why they are not.
   a. 0555.34120122190 – Instal 1680' – 6" P Ip – Betterment: Snow: Par - $285,979
   b. 0559.34160088267 – Pipe Pl 6" 436036 – $57,602
   c. 0565.34130062345 – 4" SL London Correctional d London COR-LON - $46,192
10-4. The following three work orders are for the purchase of METSCAN Units and American Meters. Please explain the following:

Work order & Description	Total
0549.34D00342008 – METSCAN	$2,687,010
0567.34D00342011 – American AR250	$1,000,887
0567.34D00342014 – American A1250	$3,092,629

   a. Why is the purchase of METSCAN and Meters considered Growth?
   b. Are Meters and METSCAN units capitalized upon purchase? If not, how are they accounted for? If they are, are the METSCAN units and Meters (that are in stock and not set in the field) part of the CEP deferral? If yes, why?
   c. Why does the work order detail in Power Plant show the cost detail as charged to M&S?

d. Please provide the justification and approval for the work orders as they are classified as Specific Projects and not Blanket Projects.

10-5. The following referenced work orders appear to be acquisitions:

Work order & Description	Total
9501.3416A030042 – Structure Minor Ot: 695600	$1,873,751
9501.34150138531 – EMCO 10: 41600	$31,997,235

a. Please provide supporting detail for the charges.
b. Please explain how they are considered part of the CEP deferral.

10-6. Regarding work order 9501.34150138531 – EMCO 10: 41600 - $31,397,235, the work order was budgeted for $18.25 million, and the actual was $31.4 million. Please explain the reason for the overrun, and include supporting detail.

10-7. Regarding work order 0889.3415A030026 – GPS Support (Software) - $955,883, please provide the detail for the Corporate Allocated charges.

10-8. Regarding work order 0555.34160124268 – Inst 700' 6" 1550 2" Pmp; Norton: AVO - $133,357, the majority of costs associated with the referenced work order had a single-line description (provided in Revised Response to DR 1-9 Attachment 1) to install 700' of 6" pipe, and the Response to DR 4.1 indicated that it was for future growth. Please explain why future growth should be included in the CEP Deferral.

10-9. The below-referenced work orders are classified as Specifics.

Work order & Description	Total
0915.34d12202013 – Boring Machine	$57,157
0915.34d18182014 – General Tools and Equipment	$1,437,836
9109.3411A034600 – Improvements Leased Property	$30,090,840

a. Please provide work order justifications and approvals.
b. Are these project costs allocated? If so, please provide the supporting detail for the allocations.

10-10. Regarding work order 9109.3411A034600 – Improvements Leased Property - $30,090,840, please provide a detailed description of the Leasehold Improvements.

10-11. Regarding the below referenced work orders, please respond to the following requests:

Work order & Description	Total	CIAC Credit	Confidential
7607.34150151789 – Valve Ball 16" 890156	$xxx	$xxx	Highly Confidential
8599.34150087919 – SP Clean assy launch 670100	$997,260	$0	Non-Confidential
8655.34160152208 - Pm Sofidel : Pittsburgh : Us23	$xxx	$xxx	Highly Confidential
0557.34160124700 – Ss Fitting 12" 665550	$427,331	$0	Non-Confidential

a. The approval document appears not to have all the required signatures. Please provide the document with the required signatures.
b. For the two work orders above with a CIAC Credit, please explain what the credit was for and where it came from.

10-12. Regarding work order 0561.34160139991 – install 3600 2" Pmmp Skyline. Col - $701,219, please respond to the following:

a. This work order was over budget by more than 20%. Please explain what caused the overrun.
b. Please explain why this work order had Truck Maintenance charged to Cost of Removal.

10-13. Regarding work order 8693.34170131143 – Pm Lazelle Rd. 6" & 2" Pmmp- Lazelle – Col. -$1,229,281, this work order had no retirements but had a Cost of Removal contractor charge for $13,311. Please explain why.

10-14. Regarding work order 0889.3411A034608 – NiFit Transformation - $13,677,824.

a. Please provide the budget for this project and any Level II change orders.
b. Please indicate who the primary Consultant was that worked on this project and the actual cost paid vs. the contracted cost. Explain any changes in cost from the original budget.
c. If the project costs were allocated to different entities, please explain how that allocations were done.
d. Please cite the guidelines that were used to determine which phases of the project were capital and which were expense.

10-15. Regarding work order 07559.WP4468.1324 – Mains - $8,774,531, this work order had charges for outside services – Corrosion Maintenance. Please explain why Corrosion Maintenance is included on a capital work order.

10-16. The four work orders referenced below were over $100k and did not have approvals included in the work order detail. Please provide approvals, or indicate why approvals were not required.

Work order	Description	Total
8635.34150139025	Ss Tee 3w St, 2" : 665716	$1,022,032.87
8727.34160094650	2017 Maple St Amrp : Union : Sal	$2,034,101.08
8767.34160124597	Install 6486'Of 2"-4" Pm-Mp : Enderby : Par	$778,210.77
00557.WP9417.1521	Pipe, Pl, 8" : 463040	$124,901.22

10-17. For the below referenced work orders

Work order & Description	Budgeted Meter Move Out Costs	Total
7265.34110146029 - Install 39654' of 2,4,6" Pl Pipe	$750k	$1,575,357
7119.34100121126 - Pipe Pl 4" 463026	$1,156 million	$1,012,058

a. Please explain what *meter move out costs* are.
b. Please explain how this activity qualifies as capital in accordance with the Code of Federal Regulations.

10-18. The below-referenced work orders were for the purchase of METSCAN Units. The only detail provided for these work orders was the detail for additions to plant. Please provide the work order approvals, justifications, and budgets.

Work order	Description	Total
9901.34100135439	Metscan Unit : 415000	$1,744,560.57
9901.34110135971	Metscan Unit : 415000	$2,331,632.84
9901.34120136493	Metscan Unit : 415000	$1,033,775.35
09901.WP4584.1121	Metscan Unit : 415000	$1,026,885.28
09901.wp9921.1222	Metscan Unit : 415000	$1,132,341.22

CEP and Non CEP Blanket Work Orders (Projects).

10-19. Follow-up to Data Request 4-001. 0565 Blanket job type – Service line replacements and 0563 Blanket job type – Service line additions. The Company explained that 0565 type jobs are accounted for using

Blanket Accounting in which installation costs are not tracked specifically to service line replacements. The installation units are put into service at an average cost for any given taxing district and vintage year. Service line retirements do not track back to an individual service line. Installation generates a retirement unit and retires a single retirement unit, at an average original cost.

a. Please provide a sample calculation of how service line replacements are put into service and retired.
b. Please provide by job type (0563 and 0565) average service line installation costs for the IRP and CEP, by job type, by year, for 2008–2017.
c. Please provide the average service line retirement costs by year for the IRP and CEP, for job type 0565 for 2008–2017.
d. How are system line installation and replacement costs allocated between the CEP and IRP?
e. Please provide the job service line installation cost allocation percentages individually for the CEP and IRP for each year from 2011–2017.
f. If applicable, please provide the service line retirement cost allocations to the IRP and CEP for the years 2001–2017

10-20. Follow-up to Data Request 4-001. Job Type 0571 – House Regulators – Growth. Are additions to plant accounted for in the same manner as job type 0563? If not, explain how they are done? If yes, please provide the House Regulator installation cost allocation percentages individually for CEP and IRP for each year from 2011–2017.

10-21. Follow-up to Data Request 4-001, job type 7737 – Riser Replacement. Are additions and retirements to plant accounted for in the same manner as job type 0565? If not, explain how they are done. If yes, please provide the riser replacement installation and retirement cost allocation percentages for CEP and IRP separately for each individual year from 2011–2017.

10-22. Follow-up to Data Request 4-001. Project identified as growth in the CEP. The Company has identified job types 0563 (service lines) and 0571 (House Regulators) as growth projects. The job types represent additions to plant without retirements. The CEP allows growth projects. Please explain why the CEP growth projects did not precipitate a CEP revenue offset.

General Work Order Requests

10-23. The following attached list of 57 work orders had truck maintenance and/or tool maintenance and also had truck and/or tools clearings charged was charged as work order additions.

a. Please provide the detail for what is included in Truck and Tools clearings.
b. Why are maintenance charges included on a capital work order?
c. Explain how charging maintenance and also capital clearings for Trucks and Tools is not a duplicate charge.
d. What is included in the maintenance charges that is not included in the capital clearing?

Work order	Description	Total
CEP Specifics		
0561.34160139991	Install 3600'-2"Pmmp : Skyline : Col	$701,219
8323.34120086584	Pm Replace Tb Station : Fairwood : Col	$1,608,217
8693.34160139766	Pm Inst 2100'-6"Cshp : Lazelle : Col	$1,394,264
8693.34170131143	Pm Lazelle Rd 6",3" & 2" Pmmp : Lazelle : Col	$1,229,281
CEP Blankets		
0563.34b08220012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$6,382,094
0563.34b08230011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$5,130,509
0563.34b08230012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$10,443,957

Work order	Description	Total
0563.34b09710011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$4,959,712
0563.34b10530011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,432,261
0563.34b11210011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,174,870
0563.34b11210012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$12,123,253
0563.34b12220011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$3,044,155
0563.34b12220012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$13,954,959
0563.34b12610011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,641,455
0563.34b12610012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$14,134,592
0563.34b13240011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$8,379,510
0563.34b13240012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$9,192,593
0563.34b13250011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$8,590,148
0563.34b13250012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$6,400,692
0563.34b15210011	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$1,053,638
0563.34b15310012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$770,159
0563.34b17210012	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,337,856
0565.34b07310032	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$469,407
0565.34b08230021	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$1,681,338
0565.34b09710032	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$561,297
0565.34b11210021	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$5,810,265
0565.34b11210031	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,383,716
0565.34b12220021	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,090,507
0565.34b12610021	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,064,474
0565.34b13250032	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$3,088,830
0565.34b15210031	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$176,630
0571.34b08230081	Regulator, House, Less 2" : 570098	$1,481,571
Non-CEP Specifics		
0557.34140177847	Pipe, Pl, 8" : 463040	$607,190
0557.34150178077	Pipe, Pl, 6" : 463036	$232,011
7445.34130093974	Pipe, Pl, 2" : 463016	$815,104
7689.34150123967	Pipe, Pl, 4" : 463026	$746,271
8315.34120136832	Pipe, Pl, 4" : 463026	$482,725
8421.34130122816	Pipe, Pl, 6" : 463036	$583,928
8509.34140117005	Pipe, Pl, 4" : 463026	$1,244,031
8553.34140116917	Pipe, Pl, 4" : 463026	$774,942
8677.34160117733	Pipe, Pl, 4" : 463026	$486,568
00909.wp5312.1424	Computer, Digital : 116200	$497,169
Non-CEP Blankets		
7737.34b06510052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$8,297,343
7737.34b07330052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$1,172,371
7737.34b08220053	Riser Replacement : 655299	$4,437,095
7737.34b08230053	Riser Replacement : 655299	$8,969,146
7737.34b09710053	Riser Replacement : 655299	$3,820,455
7737.34b11210052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$40,130,047
7737.34b12220052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$18,380,934
7737.34b12610052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$17,663,459
7737.34b13240052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$10,417,855
7737.34b13250052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$19,334,043
7737.34b13250053	Riser Replacement : 655299	$14,200,574
7737.34b14410053	Riser Replacement : 655299	$3,261,866
7737.34b15310052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$2,925,482

Work order	Description	Total
7737.34b17210052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$8,637,064
7737.34b19430052	Serv M/C - Pl, Less 3" : 655296, Serv C/M Pl, Less 3" : 655596	$1,618,369

Other Requests

10-24. CEP Growth Projects: For the years 2011–2017, the Company has recorded the following additions to plant for growth projects:

Year	Growth Totals from REVISED Data Response 1-9 Attachment 1
2011	$6,463,621
2012	$32,485,780
2013	$38,068,779
2014	$43,127,243
2015	$48,444,906
2016	$57,410,409
2017	$67,052,159

a. Please explain in detail what caused the upward trend in growth from year to year.
b. What percentage of growth was actual vs. what was anticipated?
c. Does the Company have any mains or regulator stations not active? If so, what are they, and what was the cost to install them?
d. What areas of the Company service area have experienced growth either through increased customers or increased demand?
e. What is the percentage increase in growth system wide for each year from 2011 through 2017?
f. What is the change in gas sold (MCF) by year from 2011 through 2017?

10-25. Work Order NCSP16COMPLYC - Training and standards program - $54,491.45
a. Please explain in detail what the program was for?
b. What was the total project cost?
c. How were the project costs allocated to the Company?
d. Why is a Training and Standards program considered a capital activity?
e. How was the actual training charged (capital/expense)?
f. Was this employee training only? If not, who else was trained, and how were they billed?

Set 11 – Submitted on July 31, 2018

Follow-up to Data Request Response 4-001—Work Order (Project) sample selection CEP and Non-CEP. CEP-Specific and Non-CEP Work Orders (Projects)

11-1. Work order 9409.3404A034024 - Post In-Service Carrying Charge (2004-2008): PISCC - $12,909,832.
a. Provide a detailed explanation of what the charges represent
b. Why are the charges considered capital?
c. Why would a work order accrue PISCC?
d. Why is PISCC different from AFUDC that would be accrued on a work order while it is in CWIP?

11-2. Work order 7737.34B13250053 – Riser Replacement -655299 - $14,200,574. The work order additions to plant included outside service—Maintenance activity not otherwise identified.
a. Please explain what the charges are for.
b. Why should maintenance charges be included in a capital work order?

11-3. The following work orders were for replacement work and did not have Cost of Removal Charges. Please explain why.

a. Work Order 7355.34120072925 - Repl. 10840'-2",4",6",8" Pmmp : 8th : Market St Amrp Ph 1- $2,275,883.
b. Work Order 7377.34120062308 Repl 8809' 4",2" P-Mp : Kenton A A : Spr - $392,554.
c. Work Order 7445.34130093974 - Pipe, Pl, 2": 463016 - $815,104.
d. Work Order 7485.34130106479 - Pipe, Pl, 2”: 463016 - $370,100.

Set 12 – Submitted on August 3, 2018

Follow-up to Data Request Response 6-003, Attachment 1—Anomaly Listing by Account and Year

12-1. Please provide further explanation for the following anomalies:

a. Account 30300—Intangible Miscellaneous, item b: The response includes the designation of $(1,370,399) as CIAC intangibles. Please explain the function of CIAC for intangibles, who the CIAC was from, and the reason it is used in this case.
b. Account 30300—Intangible Miscellaneous, item f: The response mentions 59 software projects. Please provide a narrative of the purpose for this seemingly large number of software additions in 2017.
c. Account 37500—Distribution Structures and Improvements, item a: Please explain what lease terms expired.
d. Account 37500—Distribution Structures and Improvements, item e: Please provide the accounting entries for the sale of the building—$(387,000).
e. Account 37500—Distribution Structures and Improvements, item f: Please provide the accounting entries for the sale of the Toledo Edison facility—$(3,799,342)
f. Account 37500—Distribution Structures and Improvements, item h: Please provide the accounting entries for the retirement of Bangs facility—$(1,150,000)
g. Account 38500—Distribution Industrial Meas and Reg Station Equipment, item a: Please explain how the Company considers gauges and valves in account 385 to be fully depreciated.

Set 13 – Submitted on August 6, 2018

13-1. Revenue Offset:

Case No 11-5351-GA-UNC Finding and Order dated August 29, 2012.

(32)

(b) Columbia should offset the monthly regulatory asset amount charged to the CEP by those revenues generated from the assets included in the CEP for SFV customers, non-SFV customers, and any other revenue sources directly attributable to CEP investments.

(c) Columbia should maintain sufficient records to enable Staff to verify that all revenue generated from CEP investments is accurately excluded from the total monthly deferral. (page 12)

Case No. 17-2202-GA-ALT Amended Application

Since 2012, Columbia has been filing annual updates by April 30 in Case Nos. 12-3221-GA-UNC, et al., detailing the monthly CEP investments and the calculations used to determine the associated deferrals. The annual information filings have also included all calculations used to determine the monthly deferred amounts, including a breakdown of the investments (by categories of capital investment), post-in-service carrying costs, depreciation expense, property tax expense, <u>and all incremental revenue</u>, as well as the capital budget for the upcoming year. (page 2)

Calculation of the CEP Deferral

Total Monthly Deferral = (PISCC) + (Depreciation Expense) + (Property Taxes) – (Incremental Revenues)

….

Incremental Revenue = [(Current Month's Customers – Baseline Customers)

* (Cost Portion of Rate)] + [(Consumption by Non-SFV Customers Directly Attributable to Program Investment) * (Cost Portion of Rate)] + (Other

Revenues Directly Attributable to Program Investment)

(page 4)

a. Please identify the Schedule/Exhibit number and line number provided in the Amended Application in Case No. 17-2202-GA-ALT where the incremental revenue is excluded from the CEP monthly deferral calculation?
b. Please provide the work papers since the inception of the CEP Deferral that calculated the incremental revenue (or proof that there is no incremental revenue).
c. How does the Company identify CEP revenue generating projects?
d. How does the Company calculate the incremental revenue from the CEP revenue-generating projects?
e. If the Company does not reflect incremental revenue from CEP projects in the CEP monthly deferral, please explain why not.

<u>Set 14 – Submitted on August 17, 2018</u>

14-1. Follow up to Data Request response 4-1, Work Order NCSF16COH20C – Parking lot, $106,786. This Work Order appears to be over budget by 85%. Please provide an explanation for the budget over run.

14-2. Follow up to Data Request 10-17. Part b. The Company response indicates that meter move out costs when done in conjunction with a service line replacement are capitalized. When done without a service line replacement this activity is considered expense. Please provide the following by year from 2008-2017.

a. Total number of Meters moved from inside to outside.
    i. Total number of Meters moved from inside to outside that were expensed
    ii. Total number of Meters moved from inside to outside that were capitalized in conjunction with a service line replacement.
    iii. Total costs of meters expensed, including installation.
    iv. Total costs of meters capitalized, including installation.
b. The total number of Meters system wide that remain inside as of December 31, 2017.

<u>Set 15 – Submitted on August 24, 2018</u>

15-1. Follow up to Data Request response 12-1a: Regarding the $(1,370,399) of CIAC intangibles, the Company explained that the items "consist of one with Consolidated South Supply Line of $(876,466), two with Columbia Transmission Company (part of CPG) of $(315,357), and one with Cooper Foster Park-Amherst of $(178,576). These were payments from Columbia of Ohio made to improve the assets on behalf of our customers." Please list the actual dates that the specified CIACs were received by the Company from the contributors and show the accounting for each.

<u>Set 16 – Submitted on August 24, 2018</u>

16-1. Follow up to Data Request 4-001. Please provide the detail of how the charges were allocated to the Company for the following work orders.
a. NCSE16DPRMC – Computer Software 121000 - $339,896
b. NCSP16CDREPOC – Computer Software 121000 - $343,859
c. NCSP16PLNBDGTC – Planning and Budgeting Cap - $1,019,730.

Set 17 – Submitted on August 24, 2018

17-1. Reference response to Data Requests 1-6 (Schedule B-3.2) and 6-5: Please explain why the following FERC accounts on Schedule B-3.2 have different depreciation accrual rates than those approved by the Commission and provided in response to Data Request 6-5.

		Depreciation Accrual Rate	
Account No.	Account Title	B-3.2	Approved
37500	Structures and Improvement	2.71%	
375.34	Structures and Improvement - Meas. & Reg.		2.73%
375.56	Structures and Improvement - Ind. Meas. & Reg.		3.75%
375.70	Structures and Improvement - Other Dist. System		2.71%
375.70	Structures and Improvement - Communications Structures		2.00%
38100	Meters	4.24%	
381.00	Meters		2.28%
381.00	Automatic Meter Reading Devices		6.67%
38700	Other Equip.	4.55%	
387.00	Other Equip.		5.83%
387.00	Other Equip. - Customer Information Services		4.55%
39100	Office Furniture and Equipment	10.09%	
39100	Office Furniture and Equipment		5.00%
39100	Office Furniture and Equipment - Info. Sys.		20.00%
39400	Tools, Shop, and Garage Equipment	4.91%	
39400	Tools, Shop, and Garage Equipment		4.00%
39400	CNG Equipment		10.00%

List of Interviews Conducted

1. Plant Accounting Interview on June 22, 2018 at 9am
   a) Interviewees: Jeff Gore, Corporate Accounting – Controller, Matt Ruth, Corporate Accounting (Asset Accounting) – Mgr Accounting and Nick Drew – Director of SEC – Accounting Policy Department
2. Engineering & Work Order Development Interview on June 26, 2018 at 10am
   a) Interviewees: Eric Slowbe, Capital Execution (Engineering Srvcs COH) – Principal Engineer
3. Major Events and IT Interview on July 2, 2018 at 11am
   a) Interviewees: Kim Honaker, Corporate Accounting (Business Applications) - Mgr. Business Applications; Dyana Porterfield, Corporate Accounting (Business Applications) - Lead Business Application Analyst; Greg Skinner, Office of the CTO (IT Infrastructure) - VP IT Infrastructure; and Greg Kovacs, Office of the CTO (IT Services) - Dir PMO
4. Blankets Interview on July 12, 2018 at 10am
   a) Interviewees: Andrew Metz, Diana Beil, Matt Ruth, and Bill Rousell
5. Capital Budget Interview on July 18, 2018 at 10am
   a) Interviewees: Andrew Metz, Diana Beil, Eric Belle (Director of Supply Chain Services – Previously Capital Planning Director) Eric Slowbe (Principle Engineer CGO), Mike Sucharski (Engineering Manager CGO), JR Barnhart (Capital Planning Leader Ohio), Adam Stanley (Finance Capital Budget Manager), Liz Eisenhardt (Director of Capital Planning), and Lloyd Jackson (Finance Director)

APPENDIX C: 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.

- FERC 303 April 2014 - To Select for Sample
- IIA Sampling Guide of IA - PPS Sampling
- Inspection Results vr August 2 2018
- Spending percentages
- Work Order Testing Steps 180529
- Work Papers to create graphs in final Rpt section 10 Costs CAF Aug 27 2018
- WP 17-2202-GA-ALT Adjustments and Section B Restated
- WP 17-2202-GA-ALT BRCS DR Set 1-7 Attachment A Annual Info Filings
- WP 17-2202-GA-ALT BRCS DR Set 1-9 REVISED Attachment A (Pivot only by Budget Mapping)
- WP 17-2202-GA-ALT BRCS DR Set 1-9 REVISED Attachment A
- WP 17-2202-GA-ALT BRCS DR Set 1-27 Attachment A Backlog
- WP 17-2202-GA-ALT BRCS DR Set 6-7 Attachment A-Subaccounts
- WP 17-2202-GA-ALT Roll Forward Variances
- WP 17-2202-GA-ALT Sensitivity and Sample Size - Intervals
- WP 17-2202-GA-ALT Set 1 No 6 Depreciation Rate Verification
- WP 17-2202-GA-ALT Staff DR 4 Exhibit J Financial Schedules
- WP CEP PPS Sample and Judgement
- WP Columbia Gas Testing Matrix on CEP and NON-CEP Samples Final–Confidential
- WP Columbia Timeline of Filings
- WP Non-CEP PPS Sample and Judgement
- WP Pulling Sample CEP
- WP Pulling Sample Non-CEP
- WP Variance Sch B2.3 to PUCO Annual Report

Appendix D: Recast Plant in Service Schedules

COLUMBIA GAS OF OHIO, INC.
CASE NO. 17-2202-GA-ALT
PLANT IN SERVICE SUMMARY BY MAJOR PROPERTY GROUPINGS (Restated)
AS OF DECEMBER 31, 2017

DATA: 12 MOS. ACTUAL
TYPE OF FILING: ORIGINAL
WORK PAPER REFERENCE NO(S):

SCHEDULE B-2
PAGE 1 OF 1

LINE NO.	MAJOR PROPERTY GROUPINGS	As Filed	Recommended Adjustment	Adjusted	ALLOCATION %	ALLOCATED TOTAL	ADJUSTMENTS	ADJUSTED JURISDICTION
		$		$		$	$	$
1	INTANGIBLE	$50,373,413	$0	$50,373,413	100%	$50,373,413	$0	$50,373,413
2	DISTRIBUTION	$3,954,365,476	($205,710)	$3,954,159,766	100%	$3,954,159,766	$0	$3,954,159,766
3	GENERAL	$74,713,746	$0	$74,713,746	100%	$74,713,746	$0	$74,713,746
4	TOTAL	$4,079,452,634	($205,710)	$4,079,246,924		$4,079,246,924	$0	$4,079,246,924

COLUMBIA GAS OF OHIO, INC.
CASE NO. 17-2202-GA-ALT
PLANT IN SERVICE BY ACCOUNTS AND SUB ACCOUNTS
AS OF DECEMBER 31, 2017

SCHEDULE B-2.1
PAGE 1 OF 3

DATA: 12 MOS. ACTUAL
TYPE OF FILING: ORIGINAL
WORK PAPER REFERENCE NO(S): WPB-2.1a

LINE NO.	ACCT NO.	ACCOUNT TITLE	As Filed	Recommended Adjustment	Adjusted Total Company	ALLOCATION %	ALLOCATED TOTAL	ADJUSTMENTS	ADJUSTED JURISDICTION	Adjustment
					$		$	$	$	
1		INTANGIBLE PLANT								
2	30100	Organization	$25,937		$25,937	100.00%	$25,937	$0	$25,937	
3	30200	Franchise and Consents	$0		$0	100.00%	$0	$0	$0	
4	30300	Miscellaneous Intangible Plant	$50,347,476		$50,347,476	100.00%	$50,347,476	$0	$50,347,476	
5		TOTAL INTANGIBLE PLANT	$50,373,413	$0	$50,373,413		$50,373,413	$0	$50,373,413	
			$		$		$	$	$	
1		DISTRIBUTION PLANT								
2	37400	Land and Land Rights	$27,582,296		$27,582,296	100.00%	$27,582,296	$0	$27,582,296	
3	37500	Structures and Improvement	$29,808,677		$29,808,677	100.00%	$29,808,677	$0	$29,808,677	
4	37600	Mains	$1,912,107,538	($172,079)	$1,911,935,459	100.00%	$1,911,935,459	$0	$1,911,935,459	#1 and #2
5	37800	Meas. And Reg. Sta. Equip.-General	$55,294,441		$55,294,441	100.00%	$55,294,441	$0	$55,294,441	
6	37900	Meas. And Reg. Sta. Equip.-City Ga	$21,104,432		$21,104,432	100.00%	$21,104,432	$0	$21,104,432	
7	38000	Services	$1,507,189,082	($33,631)	$1,507,155,451	100.00%	$1,507,155,451	$0	$1,507,155,451	#3
8	38100	Meters	$204,884,238		$204,884,238	100.00%	$204,884,238	$0	$204,884,238	
9	38200	Meter Installations	$60,928,046		$60,928,046	100.00%	$60,928,046	$0	$60,928,046	
10	38300	House Regulators	$61,720,609		$61,720,609	100.00%	$61,720,609	$0	$61,720,609	
11	38400	House Regulator Installations	$33,302,527		$33,302,527	100.00%	$33,302,527	$0	$33,302,527	
12	38500	Industrial Meas. And Reg. Sta. Equip.	$13,669,111		$13,669,111	100.00%	$13,669,111	$0	$13,669,111	
13	38600	Other Prop. On Customers' Premises	$0		$0	100.00%	$0	$0	$0	
14	38700	Other Equip.	$26,774,478		$26,774,478	100.00%	$26,774,478	$0	$26,774,478	
15		TOTAL DISTRIBUTION PLANT	$3,954,365,476	($205,710)	$3,954,159,766		$3,954,159,766	$0	$3,954,159,766	
1		GENERAL PLANT								
2	39000	Structures and Improvement	$14,957,751		$14,957,751	100.00%	$14,957,751	$0	$14,957,751	
3	39100	Office Furniture and Equipment	$27,771,687		$27,771,687	100.00%	$27,771,687	$0	$27,771,687	
4	39200	Transportation Equipment	$1,240,924		$1,240,924	100.00%	$1,240,924	$0	$1,240,924	
5	39300	Stores Equipment	$291,257		$291,257	100.00%	$291,257	$0	$291,257	
6	39400	Tools, Shop, and Garage Equipment	$28,015,503		$28,015,503	100.00%	$28,015,503	$0	$28,015,503	
7	39500	Laboratory Equipment	$38,532		$38,532	100.00%	$38,532	$0	$38,532	
8	39600	Power Operated Equipment	$1,766,659		$1,766,659	100.00%	$1,766,659	$0	$1,766,659	
9	39800	Miscellaneous Equipment	$631,433		$631,433	100.00%	$631,433	$0	$631,433	
10		TOTAL GENERAL PLANT	$74,713,746	$0	$74,713,746		$74,713,746	$0	$74,713,746	
11		TOTAL PLANT	$4,079,452,634	($205,710)	$4,079,246,924		$4,079,246,924	$0	$4,079,246,924	

COLUMBIA GAS OF OHIO, INC.
CASE NO. 08-0072-GA-AIR
RESERVE FOR ACCUMULATED DEPRECIATION
AS OF DECEMBER 31, 2017

DATA: 12 MOS. ACTUAL
TYPE OF FILING: ORIGINAL
WORK PAPER REFERENCE NO(S):

SCHEDULE B-3
PAGE 1 OF 1

LINE NO.	MAJOR PROPERTY GROUPINGS & ACCOUNT TITLES	As Filed TOTAL COMPANY PLANT INVESTMENT	Adjusted TOTAL COMPANY PLANT INVESTMENT	As Filed	Recommended Adjustment	RESERVE BALANCES Adjusted Total Company	ALLOCATION PERCENT	ALLOCATED TOTAL	ADJUSTMENTS	ADJUSTED JURISDICTIONAL
		$	$			$		$	$	$
1	INTANGIBLE	$50,373,413	$50,373,413	$21,364,541		$21,364,541	100%	$21,364,541	$0	$21,364,541
2	DISTRIBUTION	$3,954,365,476	$3,954,159,766	$993,701,151	($18,428)	$993,682,723	100%	$993,682,723	$0	$993,682,723
3	GENERAL	$74,713,746	$74,713,746	$24,835,708		$24,835,708	100%	$24,835,708	$0	$24,835,708
4	RETIREMENT WORK IN PROGRESS	$0	$0	$0		$0	100%	$0	$0	$0
5	OTHER	$0	$0	($6,326,663)		($6,326,663)	100%	($6,326,663)	$0	($6,326,663)
6	TOTAL	$4,079,452,634	$4,079,246,924	$1,033,574,737	($18,428)	$1,033,556,308	100%	$1,033,556,308	$0	$1,033,556,308