LARGE FILING SEPERATOR SHEET

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Report of Conclusions and Recommendations on the Financial Audit of the East Ohio Gas Company d/b/a Dominion East Ohio In Regard to Case No. 07-0829-GA-AIR

Submitted April 16, 2008

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INTRODUCTION

Background

On August 30, 2007, the East Ohio Gas Company d/b/a Dominion East Ohio (DEO or Company) filed an application for an increase in its gas distribution rates in Case No. 07-829-GA-AIR. DEO is an Ohio corporation engaged in the business of supplying natural gas to approximately 1.2 million customers in northeastern, western, and southeastern Ohio, all of whom will be affected by this Application. DEO is a public utility as defined by R.C. 4905.02 and 4905.03(A)(6), Ohio Revised Code.[1]

DEO proposes a test year consisting of the twelve-month period ending December 31, 2007, and a date certain for property valuation of March 31, 2007.[2] The Company estimates that the rate changes proposed, if granted in full, would increase gross revenues by approximately $75 million or 7.1% annually over the test period gross revenues generated from providing service to customers. The requested rates, if granted in full, would result in a net base revenue increase of approximately $72.5 million.[3]

DEO stated that it had filed its application to recognize in rate base its substantial investment in pipelines, meters, and other jurisdictional assets since its last rate case and to generate sufficient revenues for the Company to pay its operating expenses, service its debt, and provide an adequate rate of return on its property used and useful in the rendition of gas service to its customers. DEO's current base rates, authorized by the Commission in Case No. 93-2006-GA-AIR, are based on a test year beginning October 1, 1993, and ending September 30, 1994, and a date certain of December 31, 1993. Since that test year, the property used and useful in the rendition of gas service to the customers affected by the Application has materially increased, as have many of the expenses associated with providing that service. As a result, the current rates are projected to provide a 4.31% rate of return for the proposed test period. This is substantially below the 10.67% return found reasonable for the Company by the Commission in DEO's last base rate proceeding. The Company submits that a return of 8.59% is fair and reasonable.[4]

DEO's application also states that the Company proposes to recover the costs of its proposed system-wide installation of automated meter reading (AMR) equipment, through an AMR Cost Recovery Charge. This flat monthly charge will be added to the otherwise applicable customer service charge for all customers under the following rate schedules: GSS, LVGSS, ECTS, LVECTS, GTS, and TSS. The charge is proposed to recover the depreciation, incremental property taxes and post in-service carrying costs associated with the installation of AMR equipment throughout DEO's system.[5]

[1] Application of DEO, August 30, 2007, pp. 1-2, ¶1.
[2] Application of DEO, August 30, 2007, p. 4, ¶9.
[3] Application of DEO, August 30, 2007, p. 4, ¶10.
[4] Application of DEO, August 30, 2007, p. 4, ¶11.
[5] Application of DEO, August 30, 2007, p. 3, ¶5.

Subsequent to the Company's application, DEO requested and was granted several waivers of its standard filing requirements. The following standard filing requirements are impacted:

- Chapter II(C)(32) requiring monthly management reports providing results of operations and comparison of actual to forecast for the test year and the twelve months immediately preceding the test year. Reports covering the test period should be provided as they become available.

  DEO does not, in the ordinary course of business, produce reports comparing actual results to forecasts. The Company stated that it would work with Staff to provide comparable information that satisfies the intent of Chapter II(C)(32).

- Chapter II(C)(37) and (44) requiring information regarding federal and state income tax returns.

  DEO expressed concern regarding the confidentiality of these documents, and they will be made available for review only at DEO's office.

- Chapter II(C), paragraph (D)(5) requiring the filing of Schedule C-8. The data in Schedule C-8 includes: (i) the current case estimate; (ii) most recent prior case actual; (iii) most recent prior case estimate; (iv) next most recent case actual; and (v) the next most recent case estimate.

  DEO was unable to locate records of the actual rate case expense for the most recent case (category ii above). This case, 93-2006-GA-AIR, was filed over 13 years ago. The information will not be made available.

- Chapter II Schedule C-12.1 Revenue Statistics-Total Company
  Chapter II Schedule C-12.2 Revenue Statistics-Jurisdictional
  Chapter II Schedule C-12.4 Sales Statistics-Total Company
  Chapter II Schedule C-12.4 Sales Statistics-Jurisdictional

  Information for the most recent five years will be filed in accordance with the filing requirements. For the test year and future years, sales and revenue projections will be filed by residential and non-residential classes as opposed to residential, commercial, and industrial classes. Non-residential combines the former commercial and industrial classes.

- Chapter II(F)(B) requiring projected income statements to follow the FERC chart of accounts.

  DEO does not plan or forecast by FERC accounts but rather by a general ledger of accounts. Projected income statements will be filed but not in accordance with the FERC chart of account.[6]

Project Scope

Blue Ridge Consulting Services, Inc. (Blue Ridge) was retained to conduct an audit and analysis of the components, backup support, and underlying management processes that go into the development and determination of the revenue requirements applied for by the Company. Blue Ridge submitted a preliminary work plan in its proposal dated November 14, 2007, which was subsequently approved and implemented. The scope of the investigation was designed to determine (1) whether the Company's filed exhibits related to test year operating income, rate base, and other issues and the underlying information, data, and calculations were reasonable for ratemaking purposes and (2) whether the financial and statistical records reliably support the data in the filing. Therefore, this audit is not intended to provide a basis for expressing an opinion on the financial statements of the Company as a whole.

The scope of Blue Ridge's audit includes four major areas:

A. **General Requirements** aimed at furthering the understanding of the Company's management, operations, policies, and practices
B. **Operating Income** including reviews of major changes in revenues and expenses for the past 5 years
C. **Rate Base** including the major plant additions and retirements
D. **Allocations** including the Cost Allocation Manual associated with affiliate transactions and jurisdictional allocators.

[6] PUC of Ohio Order dated August 15, 2007.

EXECUTIVE SUMMARY

The following is a summary of Blue Ridge's significant findings, conclusions, and recommendations. Overall, the processes, procedures, and practices of Dominion East Ohio Gas Company (DEO or the Company) provide assurance that the information contained in its base rate filing can be relied upon for setting rates after correcting for those issues noted herein. However, as noted below and throughout the report, there are several areas that the Company should address to present a more accurate and less-confusing presentation.

Blue Ridge appreciates the Company's cooperation in conducting this audit and facilitating the document and information responses. Nevertheless, gathering of information for the audit presented challenges due in part to the length of time since the last rate case in combination with the mergers that occurred in the ensuing years. The Company had difficulty retrieving data especially prior to 1997 (before the Oracle system was in place). Blue Ridge attempted to trace Application data back to available data, which, in some cases during the pre-1997 time period, had to be FERC Form 2s.

Additionally, responses to data requests (DRs) submitted to the Company took an average of 27 days to be returned (77 was the longest turnaround response time for an individual DR). Blue Ridge does realize that the audit was an interruption to the Company's normal operations, and also does believe that the Company support personnel did work diligently in order to respond to the DRs. However, from discussions with the Company, it appears that the turnaround difficulty was due, not to lack of individual effort, but rather to a possible lack of adequate resources dedicated to the audit response. DEO is a part of a family of Dominion companies. It would seem appropriate that when resource deficiencies were noted, additional personnel could have been "borrowed" from parent or sister organizations to ensure that the audit progressed in a timely fashion. As a result, the audit deadline had to be extended on three occasions due largely to delays in receiving data request responses from the Company.

A. GENERAL REQUIREMENTS

Blue Ridge was able to verify the mathematical accuracy of the vast majority of the values in the Company's revenue requirement model and was able to trace those values back to cited sources. However, Blue Ridge did discover a number of errors in the Company's filing. The mathematical errors discovered by Blue Ridge overstate the revenue deficiency by $866,855.

Recommendation

Blue Ridge recommends that the Company incorporate into their revenue requirements model the corrections and updates noted and that the resultant appropriate adjustments be made to the revenue deficiency in the Company's filings.

Blue Ridge was unable to confirm the accuracy of a few inputs to the Company's revenue requirement model. First, Blue Ridge was not able to verify the current accrual rate and average service life for Miscellaneous Intangible Plant – Computer Software (Account 303) on Schedule B-3.2 Current (page 6). Second, Blue Ridge was unable to verify the accuracy of the Company's PIPP Revenues on line 2 of Revised WPB-5.1. Third, Blue Ridge was unable to reconcile some of the Company's depreciation schedules to the Company's FERC Form 2s. Specifically, the depreciation schedules in *Supplemental #21 B-3.3 – Combined 1997-2007_Rev.xls* for years 1997-2001 were not reconciled to the Company's FERC Form 2s for those years.

Recommendation

Blue Ridge recommends that the Company be required to explain and/or correct the accrual rate and average service life for Account 303 Miscellaneous Intangible Plant – Computer Software that was not verified in relation to the supporting documentation provided by the Company. In addition, the Company should provide an explanation and/or supporting documentation for the PIPP Revenues on Revised WPB-5.1.

DEO's revenue requirement model compiles a significant amount of data from various sources that, through a series of calculations, rolls up into the revenue requirement calculated by the Company. Blue Ridge found a number of instances in which the Company had hard-coded numbers into the model that were derived elsewhere in the model itself or that resulted from calculations in other supporting schedules outside the model that could have been linked via formulas throughout the revenue requirement model. This would have eliminated actual and potential data entry errors, and it would have allowed Blue Ridge to verify all relevant inputs and assumptions more efficiently using the audit tools within Microsoft Excel.

Recommendation

For future rate cases, Blue Ridge recommends that the Company maximize the use of formula linking within the electronic revenue requirement model to streamline the review process and minimize errors in data input.

B. OPERATING INCOME

Blue Ridge reviewed the Company's operating income and the validity of the information contained in the income statement and revenue requirements model. Blue Ridge also reviewed the past trends in expenses and budgets to determine whether any anomalies or extraordinary issues affected the revenues and/or costs included in the Company's filing.

Blue Ridge found DEO's direct-mapping process confusing to replicate and noted that some of the natural accounts did not map to the corresponding FERC account according to the SAP direct-map table provided in discovery. These differences make account comparisons between FERC and SAP income statements difficult without Company-prepared reconciliations explaining the differences.

Recommendation
For future rate case applications, the Company should provide reconciliations that tie the natural account income statements to the FERC income statements with explanations supporting all adjustments made outside the direct-mapping and tracing process to produce the FERC income statements.

The 2007 test year revenue and expenses do reflect some significant variances from the 5-year historical average. However, the changes in the Company's test year operations appear to be explained adequately by the Company.

With the exception of 2006, both revenues and expenses have been trending upward over the past several years and the Company's operating income has remained relatively stable. The Company's adjusted test year projections contemplate significantly reduced revenues, slight decreases in costs, and substantially lower operating income in total and on a per customer basis. However, 2007 revenues were higher than the Company anticipated while costs were lower than expected.

Recommendation
Given the amount by which the Company's adjusted test year operating income deviates from previous trends and its actual performance for 2007, Staff may wish to consider a detailed review and, potentially, regulatory adjustments to the Company's proposed test year adjustments. Furthermore, the Company's Schedule C-11.2 should also be revised to reflect unadjusted test year values in 2007 to provide a relevant comparison of 2007 results to actual results for the prior five years.

DEO's 2007 budget appears to be generally representative of historical trends. Certain increases of shared service allocations, however, may warrant further investigation. These are discussed in the section labeled Other Independent Analysis.

Blue Ridge's assessment of the Company's budget process is that it is sound and can be relied upon to produce reasonably accurate budgeted operating expenses and capital additions. Although corporate executive management and business segment senior management are integrally involved in the development of the original budget and Five-year Plan as well as recurring operations meetings to understand the causes of variances from the plan, we found that DEO's approval process for its load forecast does not require formal written approval by senior management before the forecast is sent to other departments.

DEO's 2007 O&M budgeting process appears to be reasonably accurate based upon the comparison to the Company's actual results for 2007. However, the Company's load forecast may have been somewhat optimistic given that retail revenue was $75 million or

10.7% less than the test year forecast. Overall, the Company's 2007 actual results appear to support the unadjusted test year operating income relied upon by the Company in its filing.

Most recent prior year budget to actual results (2006) contained significant variances due primarily, on the revenue side, to the migration of sales customers to the Energy Choice program in which they purchase natural gas commodity service from third party suppliers. On the O&M side, the PIPP rider rate during 2006 was not reflected in the budget since the application was filed after the 2006 plan was established.

Recommendation

Due to the significant variances in prior year actual to budget comparison, Blue Ridge recommends that the Commission focus on the comparison in Task B.8 as a benchmark of the reliability of the budget process instead of the comparison of the 2006 budget to 2006 actual results.

Trends in the Company's consumption and customer data reflect relatively stable year-over-year usage from 2002 - 2005. Consumption declined in 2006 and 2007 which may be due to the migration of customers to the Energy Choice program noted above. Actual consumption per customer for 2007 is lower than the 5-year average, but not as low as the test year projection.

Recommendation

The Staff may want to consider whether an adjustment to the Company's projected volumes and associated costs and revenues is reasonable.

Blue Ridge determined that the Company's load forecast process includes generally accepted processes, and the results meet a minimum standard acceptable for the purpose of this rate case. However, the process is not well-documented and lacks standards for internal review.

Additionally, the Company's trending process does not explicitly contemplate the effects of price elasticity and relative gas prices (average and marginal). Furthermore, DEO's trend models are static and have remained generally unchanged over the past few years. To date, DEO has begun assembling data necessary to backcast and validate its forecast; however, the data assembly began only in January 2006, and no significant validation has taken place.

Recommendation

The Company should consider documenting the load forecasting process and associated standards. Additionally, DEO should require formal approval by senior management of the load forecast based upon defined standards before it is distributed to other departments, because it is one of the most important components of the business planning process.

Blue Ridge performed a mathematical accuracy check of the Company's proposed adjustments, identified hard-coded values, requested source documentation for hard-coded values, reviewed the supporting documentation, and traced the adjustment inputs to the supporting documentation. Seven proposed adjustments have been found to be inaccurate.

Recommendation

Blue Ridge recommends that the Company make the corrections/updates identified to the Company's proposed adjustments. The mathematical accuracy of the remaining adjustments to operating income and rate base are reasonably accurate.

C. RATE BASE

Blue Ridge concluded that the balance sheet as presented in the Revenue Requirements Model for the most part reflects historical trend.

For plant additions, supporting cost files reasonably match summary information. Notable, however, is the lack of readily obtainable project documentation for projects prior to 1998. Furthermore, considerable difficulty occurred in amassing the data in a form that could be used for evaluation purposes to tie information from the audit to the Company's filing.

Recommendation

As part of its next rate filing, the Company should be prepared to demonstrate the tie-in of information from the supplemental filing to detail project and backup cost information. Should they not file for an extended period, the Company should be on notice that its data retrieval capabilities need to allow for review of specific project information even though dated.

Field visits were selected for both physical assets and intangible assets such as computer systems. No deviations from accepted norms or good utility practice were observed.

Blue Ridge believes that the Company currently has adequate policies, procedures, and practices for recording of transfers and retirements.

The Company has over-accrued its reserve deficiency. The Company is proposing an adjustment to reflect total depreciation and amortization on date certain property at proposed depreciation rates, which are supported by the latest depreciation study performed by Gannett-Fleming. To adjust its depreciation reserve to the proper amount, DEO proposes to reduce its future depreciation expenses over a ten-year period with a corresponding amount to fund the deployment of automated meter reading (AMR) equipment throughout its system and increase its demand side management (DSM) expenditures to support customer conservation programs.

Recommendation

As part of its policy recommendations, Staff should consider whether it should adopt the Company's proposal to reduce its future depreciation expenses over a ten-year period and to use a corresponding amount to fund the deployment of AMR equipment throughout its system and increase its DSM expenditures to support customer conservation programs.

The Company maintains reasonable controls and procedures relative to the categorization of lease agreements as operating or capitalized leases. However, several exceptions were identified between the Company's filing and the supporting documentation. Documentation was not provided to support the values recorded in the Company's filing for leased computer equipment. Rate base may be over or understated depending on the allocation made by DRI's IT group for the equipment assigned to DEO.

Blue Ridge found that the Company's AFUDC policy and processes for calculating the debt and equity components of AFUDC are reasonable. However, a review of the AFUDC applied to sampled work orders identified several areas that the Company should investigate. The Company's policy states that AFUDC will cease with the month during which the project or part thereof is placed in service or is available for service. But the review found 12 instances in which AFUDC was applied after the in-service dates.

Recommendation

A total of $157,514.47 is recommended to be reversed from sampled projects, thereby reducing the project costs and plant in service. The Company should investigate how one project had AFUDC in excess of 20% of the total project costs applied after the in-service date.

The Company has not included a regulatory asset and/or liability balance in rate base but is requesting to amortize costs for Workforce Reduction, Unrecovered Weatherization Costs, and Over-Recovered Order 636 Transition Costs as adjustments to its revenue requirements.

Recommendation

As part of its policy recommendations, Staff should consider the Company's proposal to amortize these regulatory asset and liability balances.

The Company provided adequate support from its accounting records for the balances in deferred income taxes accounts.

Recommendation

Although many of the components that are included within deferred income taxes reduce the Company's rate base, the Company should be required to provide additional explanation in its workpapers that support the balances that remain within deferred income taxes in its rate filings.

D. ALLOCATIONS

Costs are allocated between and among affiliate organizations based on jurisdictional, organizational, functional, and cost of service considerations. Blue Ridge reviewed and validated the jurisdictional, organizational, and functional allocation factors used in distributing service organization costs to DE-Ohio.

Blue Ridge found that the functional allocations are appropriately documented in the Cost Allocation manual or CAM and reasonably applied. Although individual DEO managers have little absolute control over DRS charges to their departments, several controls are in place to provide a level of confidence that DRS-charged costs are appropriate. First, the DRS allocation process is under regular audit evaluation. Recent audits have verified the correct application of allocations. Second, except as noted below, the trend of service costs to DEO from year to year has been relatively consistent. Third, benchmarking studies, albeit limited as to number of service categories covered, are being performed to ensure best practices and reasonable costs.

Recommendation

To ensure consistent control across all service categories, Blue Ridge recommends development of a regular benchmarking study schedule (benchmarking studies of all service categories on a five to seven year rotational basis) so that cost levels of all service categories are regularly monitored.

As specified in the CAM, affiliate transactions are rendered by DEO at cost without including the authorized rate of return.

Labor loadings appear to have been properly applied.

Training documents were reviewed and appeared satisfactory. Additionally, Blue Ridge found no violation of CAM and Code of Conduct application to the current rate case. However, audits revealed that procedures do not currently provide for (1) determining which employees should receive annual training on state standards of conduct, and (2) ensuring all applicable employees receive annual training.

Recommendation

A thorough review and enhancement of training procedures related to codes of conduct, affiliated transactions, and CAM implementation should be conducted to ensure that all Company employees are familiar with requirements, providing reasonable assurance that transactions will be executed in compliance to the governing documents. Blue Ridge found no abnormalities in application of CAM and Codes of Conduct policies and procedures; therefore, this recommendation is intended to support future assurance of proper application of the CAM and Codes of Conduct.

E. OTHER INDEPENDENT ANALYSIS (Task C.16)

Two issues were identified for further analysis. These included (1) Billing Process, Revenue Validation, & Customer Service Testing and (2) Dominion Resources Services, Inc. (Service Company or DRS) Charges to DEO.

Blue Ridge concludes that the Company's billing, revenue validation, and customer service procedures are reasonable and have sufficient controls in place to ensure that customer bills as well as the revenue recorded on the Company's General Ledger is reliable. Additionally, the Company's initiative for 2008 to increase the documented controls of the Company's billing process should identify any issues that may exist in the Company's billing process in relation to applicable requirements, which will be of further benefit to the Company's billing process.

Recommendation

The results and implementation of the Company's 2008 initiative to increase documented controls of the billing process should be reviewed in the future to determine whether the Company finds any shortcomings in the Company's billing process during this initiative and, if so, how any shortcomings are addressed by the Company.

Blue Ridge finds that the DRS costs charged to DEO for the year 2007 and, in turn, FERC Account 9923000 "Admin & General – Outside Services Employed" are significantly higher than in the previous 5 years. While the Company provided explanations for all increases, one concern remains. Without a full examination of the reasons and calculations behind the 2006/2007 incentive package, the 71% increase in Executive/Administrative Compensation seems excessive.

Recommendation

Blue Ridge recommends that the Commission may want to consider a more rigorous audit evaluation focusing on the Executive/Administrative Compensation package to determine the justification for the 71% increase over the 5-year historic average.

A. GENERAL REQUIREMENTS

Audit Team

1. Michael J. McGarry, Sr. – Lead
2. Donna Mullinax
3. Dan Salter
4. Warren Fischer
5. Patrick Phipps
6. Hallie Lawrence
7. Howard Solganick
8. Tracy Mullinax
9. Michael T. Dryjanski

Audit Objectives and Scope

Blue Ridge's audit objectives and scope as provided in the approved work plan included the following:

Task A.1-Request and review all available documents and testimony

Search the Commission files through the Internet, and request a copy of the information not available on the Commission website relating to the issues in this proceeding. This information will include the Company's minimum filing requirements and any discovery submitted prior to or at the time of the Company's filing, including, but not limited to, work papers and background information requested by Staff.

Task A.2-Initial consultation with Staff

Blue Ridge will confer with Staff and other consultants, if appropriate. The purpose of this initial consultation is to establish a proper working relationship, to receive input or recommendations, to discuss past relevant Orders, and to discuss the procedures to be followed in this proceeding.

Task A.3-Verify the mathematical accuracy of the application

Review filing for major rate and revenue requirement impacts proposed by the Company. Validate all calculations and flow-through of exhibits in the filing. Note and request explanation of calculations that cannot be validated

Task A.4-Review the Staff Report of Investigation in the Applicant's last base rate case.

Prepare list of significant and carryover issues, including any amortizations that should be discontinued or possibly credited to customers.

Task A.5-Review the Opinion and Order from the Applicant's last base rate case

Prepare list of compliance aspects from previous order

Task A.6-Review the audit report and Opinion and Order from the Company's most recent gas cost recovery case

Determine whether any crossover issues from the gas cost cases may impact base rate filing.

Task A.7-Develop a comparison of the revenue requirement from the Opinion and Order in the last base rate case to the current revenue requirement (pro forma) in the current case to assist in identifying what costs are driving the requested increase

Prepare a spreadsheet-based model comparing last case to current application highlighting major differences.

Task A.8-Interview the Applicant's management personnel and review both internal and published financial reports to assure understanding of the Applicant's operation and organization

Conduct a series of management interviews to ensure understanding of Company's operations.

Task A.9-Issue data requests for information to complete the following specific items. Each of these items will be review and incorporated within the analyses, findings and conclusions related to our assessment of the accuracy and validity of the Company's filing.

- Actuarial reports for pensions and other than pensions
- Affiliate Agreements for Inter-affiliate Transactions
- Audit Committee Minutes
- Billing Records (registers, etc.)
- Board of Director Minutes
- Chart of Accounts and Accounts Manual
- Construction Work Orders
- Construction Budgets
- Continuing Property Record (CPR)
- Corporate Budget by Month and by Function
- Current Labor Contract
- External Independent Audit Reports and Workpapers
- Franchise Fee Records (collection and payment)
- Forecast Assumptions
- General Ledger and Subsidiary Ledgers
- Income Tax Returns

- Internal Audit Reports and Workpapers
- Invoices
- List of Property Units
- FERC General Advertising Expense Acct. 930.1
- FERC Miscellaneous General Expense Acct. 930.2
- Monthly or Quarterly Operating/Financial Reports
- Monthly or Quarterly Trial Balances
- Monthly Sales by Rate Schedule and/or Customer Class
- Organizational Charts (corporate and internal reporting lines and departments)
- Payroll Records
- Property Tax Statements
- Risk Committee Minutes and Documentation
- Sample of Customer Bills (to verify rates and information)
- Standard Journal Entries

Background

The General Requirements section of the Work Plan included much of the initial activity required to complete the overall assignment. The foundational tasks performed include those items required to obtain an understanding the underlying financial, operational, procedural, and statistical data that form the basis of the Company's exhibits, calculations and support for the requested revenue increase.

General Requirements Task A.1

Task A.1-Request and review all available documents and testimony

Blue Ridge accessed the Public Utilities Commission of Ohio (PUCO) website for documents pertinent to Case Number 07-0829-GA-AIR. These documents were reviewed to establish a background understanding of DEO's application. Blue Ridge also obtained other relevant documents including the previous rate case and data requests of parties to the case. Appendix 1 provides an index list of the initial documents reviewed.

A list of preliminary data requests were submitted to the Company on December 3, 2007, prior to the formal kick-off meeting. Additional data requests were submitted through the duration of the project. A list of data requests issued is included in Appendix 2. The responses to all the data requests submitted are included with the project workpapers.

General Requirements Task A.2

Task A.2-Initial consultation with Staff

Blue Ridge held initial discussions with the PUCO Staff (Staff) upon project award to verify the overall scope and direction of this review. A formal kick-off meeting with Staff, the Company, and the Blue Ridge team was held on December 17, 2007, at the Company offices in Cleveland, Ohio.

General Requirements Task A.3

Task A.3-Verify the mathematical accuracy of the application

Background

Blue Ridge verified the mathematical accuracy of the Company's rate filing. The primary support and calculations for the Company's filing is found in the Company's revenue requirement model[7] and supporting workpapers. The revenue requirement model is a series of Microsoft Excel-based workbooks, each consisting of a number of worksheets that convert data from various sources into the Company's test year operating revenues and expenses, rate base, and adjustments. It is crucial for the revenue requirement model to be mathematically accurate. If the model is inaccurate, the Company's proposed test year rate base, revenue requirement, and/or adjustments could also be inaccurate.

Analysis

Blue Ridge reviewed case documentation, including testimony, workpapers, and supplemental information related to the Company's proposed revenue requirement and underlying calculations. Blue Ridge reviewed the Company's revenue requirement model focusing on the mathematical accuracy of the model, noting hard-coded values, checking formulae for accuracy, and checking flow-through of values throughout the model (e.g., dependents/precedents of the model).

For values in the model that include a mathematical formula, Blue Ridge checked the formula to ensure that the math was correct. For values in the model that are linked to a cell elsewhere in the model, Blue Ridge checked the link to ensure that the cell was properly linked within the model. For values that are hard-coded in the model, Blue Ridge attempted to discern the source of the value and, if the source could not be determined, issued a data request to the Company requesting explanations and/or source documentation.

Blue Ridge requested a significant number of source documents for values and calculations in the model that could not be verified or duplicated in Blue Ridge's preliminary review. Blue Ridge issued more than 50 data requests[8] to the Company seeking either explanation and/or supporting documentation for hard-coded values and calculations in the revenue requirement model and/or supporting workpapers.

Blue Ridge reviewed the information provided by the Company in response to these data requests to determine whether the numbers used in the Company's model tie to that

[7] The revenue requirement model (or Standard Filing Requirements model) consists of a series of Excel-based workbooks filed by the Company in response to Data Request BRCS-GPR-01-002 and BRCS-WF-01-002.

[8] These data requests are listed in Blue Ridge's Document Management System (DMS), which is provided as Appendix 2.

source documentation and to verify the accuracy of the calculations that flow from those numbers.

Blue Ridge also held interviews with Company personnel in Cleveland, Ohio to enhance understanding of the revenue requirement model.[9] Blue Ridge conducted follow-up discussions with Company personnel regarding hard-coded values when additional explanation was needed to determine their derivation from documentation provided by the Company.[10] For calculations or values that could not be tied back to the source cited, Blue Ridge either worked with the Company to verify that the value did indeed come from the source or issued a follow-up data request seeking clarification.

In performance of this mathematical accuracy check, Blue Ridge tracked values in the revenue requirement model via a color code/comment system. The results are provided in Blue Ridge's workpaper *A(3)_Math.Accuracy Test.zip.*[11] As indicated in the workpapers' key,[12] the notations in Blue Ridge's workpapers are defined as follows:

- Blue: indicates a value that is developed elsewhere in the revenue requirement model, and Blue Ridge verified that the value ties to the linked source.
- Light Green: indicates a value derived through a calculation/formula, and Blue Ridge determined that the calculation/formula checks.
- Bright Yellow:[13] indicates a hard-coded value, and Blue Ridge determined the source derivation of the input.
- Tan: indicates comments from Blue Ridge. Comments are added to describe sources, calculations, etc. (Note: comments related to errors found in the filing are shown in green.)
- Red: indicates a value that either could not be tied back to the source cited by the Company or that Blue Ridge determined was in error.

[9] Edwards, Oliver, Hurst & Laley - Interview on 080111 and Laley - Inteview on 071218. Also, for example, during on-site work in Cleveland, Ohio the weeks of February 18th and February 25th, Blue Ridge met with Company personnel, including the Director, Pricing & Regulatory Affairs, Manager, Regulatory & Pricing, Senior Financial Analyst, and Senior Transportation Analyst, to enhance our understanding of the underlying source documentation and calculations for schedules in the Company's filing.

[10] One example of this is the Total Payroll Taxes for Hourly Employees for years 2002-2006 on Schedule C-9.1, p. 6 of 7, line 16. Blue Ridge issued data request BRCS-WF-04-005, part 60 seeking support for these values, and the Company provided information, including pivot tables from its payroll system, as support for these values. An explanation from the Company was needed to determine how the hourly payroll taxes were calculated from the information provided.

[11] Workpaper *A(3)_Math.Accuracy Test.zip* is a zip file containing all of the workbooks included in the Company's revenue requirement model, annotated to reflect the results of Blue Ridge's accuracy check under Task A(3). The schedules replaced by the Company's revised filing were moved to a separate folder. The revised schedules were analyzed as part of the A(3) work and are included in a single folder in the zip file. An additional folder (workpapers) was added to the zip file, which consists of select, annotated workpapers that are relied upon heavily by the Company's revenue requirement model.

[12] Workpaper *A(3)_Math. Accuracy Test.zip,* file *A Schedules.xls,* tab Key.

[13] There are also several light yellow cells indicating 100% allocation to gas.

The following example illustrates the color code system used in Blue Ridge's mathematical accuracy verification workpapers.

Figure 1: Sample of Mathematical Accuracy Verification Color Coding

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Property Tax Expense
For the Twelve Months Ended December 31, 2007

Data: 3 Months Actual & 9 Months Estimated
Type of Filing: Original
Work Paper Reference Nos.: WPC-3.16

Schedule C-3.16
Page 1 of 1
Witness Responsible:
V. H. Friscic

Purpose and Description	Schedule Reference	Amount
To reflect property tax expense on date certain property at latest known rates.		
Unadjusted Property Tax Expense	C-2.1	[redacted]
Property Tax on Date Certain Property	WPC-3-16	18,596,398
Total Adjustment		$ (468,198)
Jurisdictional Allocation Percentage		100%
Jurisdictional Amount		$ (468,198)

Note (1) Schedule C-2.1 p. 8 of 8 line 9 Excel file C-1 to 2-1.xls, Tab C2.1-6
Note (2) Volume 6 Supplemental C(7) - working papers WPC-3.16

Line 1 (Unadjusted Property Tax Expense) in the above example is highlighted in blue and is based on a number developed elsewhere in the model. Line 2 (Property Tax on Date Certain Property) is highlighted in yellow and is a hard-coded number that is developed outside the revenue requirement model.[14] Lines 3 and 5 (Total Adjustment and Jurisdictional Amount) are highlighted in light green and are the result of a calculation or formula that Blue Ridge has checked. The sources of the hard-coded values are also described in the workpapers in the comments section, which are highlighted in Tan. See notes (1) and (2) above.

Findings

Overall, Blue Ridge was able to verify the mathematical accuracy of the vast majority of the values in the Company's revenue requirement model and was able to trace those values back to cited sources. However, Blue Ridge did discover a number of errors in the Company's filing.

[14] In this example, the hard-code highlighted in yellow is calculated in a supporting workpaper.

Exceptions List – Errors/Corrections to the Revenue Requirement Model

Blue Ridge created an exceptions list (shown below) containing a list of errors found in the Company's filing for which corrections should be made to increase the accuracy of the filing. The list below is a summary of the errors discovered and their impact on the Company's revenue requirement calculation.

Exceptions List

1. Schedule B-3.1, p. 2, line 7 "Cost of Removal": The correct amount for Cost of removal is $21,797,890 instead of $18,960,162, which increases the total costs of removal to $22,047,777. The impact of this correction is an increase in the revenue deficiency of $344,503.[15]

2. WPB-5.1, line 8 "Benefits": The Benefits amount on line 8 of WPB-5.1 is understated by $3,619,902.[16] The impact of this correction is an increase in the revenue deficiency of $33,078.[17]

3. Schedule B-6, p. 1, line 15 "Deferred Income Taxes for Depreciation": The deferred income taxes for depreciation includes an adjustment of $953,079 recorded in accordance with FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, which should have been removed for rate-making purposes. The impact of this correction is a decrease in the revenue deficiency of $115,703.[18]

4. Schedule C-2.1, p. 1 of 8, line 26 "Purchased Gas Cost Adjustments": In response to BRCS-WF-04-005 (subpart 4), the Company provided documentation showing that this number should be ($89,283,273) instead of ($89,118,272).[19] Therefore, the Company's filed Schedule C-2.1 overstates Total Purchased Gas Cost expense on line 27 by $165,001. The impact of this correction is a decrease in the revenue deficiency of $266,507.[20]

5. Schedule C-4, p. 1, Column 1 line 7 "Other Reconciling Items": According to the Company's response to BRCS-WF-01-003, two errors exist related to "Other Reconciling Items" on Schedule C-4. First, Other Reconciling Items inadvertently includes an adjustment increasing taxable income for Fines, Penalties, Skyboxes, etc[21] that was removed via the Schedule C-3.23 adjustment eliminating public relations expense from test year operating expenses. The

[15] Response to Data Request BRCS-WF-01-003.
[16] The correct amount is $18,174,159.
[17] Response to Data Request BRCS-WF-01-003.
[18] Response to Data Request BRCS-WF-01-003.
[19] Workpaper *A(3)_Math.Accuracy Test.zip*, Schedule C-2.1, p. 1 of 8, line 26, note 12.
[20] Workpaper *A(3)_Correction Workpapers*, pp. 19-21, tab *C-2.1*.
[21] Standard Filing Requirement, WPC-4.1, Excel row 38. Amount $162,750. See also, WPC-4.2.22.

impact of this error is a decrease in the revenue deficiency of $91,287. Second, Other Reconciling Items inadvertently included an adjustment increasing taxable income related to Meals and Entertainment[22] that was removed via Schedule C-3.23 adjustment eliminating public relations expenses from test year operating expenses. The impact of this error is a decrease in the revenue deficiency of $36,404.

6. Schedule C-3.17, line 1 "Annualization of merit and wage increases" & C-3.18 "Payroll Taxes": In response to BRCS-WF-01-003, the Company provided a revised WPC-3.17, which is a corrected calculation of the adjustment for annualized wages, salaries and benefits. The revised WPC-3.17 uses updated overtime and benefits percentages. Because WPC-3.18 relies on the overtime adjustment calculated in WPC-3.17, the revised WPC-3.17 results in a change to the Overtime adjustment,[23] which results in an $84 increase in the C-3.18 adjustment. The impact of these corrections is an increase in the revenue deficiency of $67,260.[24] Note that the Company's revised WPC-3.17 did not correct the understatement of salaries paid on WPC-3.17.[25] When this correction is added, the revisions to C-3.17 and C-3.18 increase the revenue deficiency by $68,319.[26]

7. Schedule C-3.23, line 1 "Public Relations Expense": Due to an error on WPC-3.23, the public relations expense adjustment is understated by $63,249.[27] The impact of this correction is a decrease in the revenue deficiency of $66,403.[28]

8. Schedule C-3.27, line 1 "Weatherization Funding": The amount of $2,500,000 on this schedule should be $3,000,000 to reflect the entire weatherization expense from the test year (rather than just the ratepayer-funded portion). The impact of this correction is a decrease in the revenue deficiency of $518,270.[29]

9. Schedule C-3.30, line 1 "Other Post Employment Benefits": The benefits percentage on WPC-3.30 should be 87.86% instead of 78.45%, which results in a change of this adjustment from ($1,732,789) to ($1,940,635).[30] The impact of this correction is a decrease in the revenue deficiency of $218,211.[31]

In addition to the errors listed above, whose correction would increase the mathematical accuracy of the Company's filing, Blue Ridge discovered some errors that do not impact

[22] Standard Filing Requirement, WPC-4.1, excel row 39. Amount $104,852. See also, WPC-4.2.23.
[23] Standard Filing Requirement, WPC-3.18, line 3 "Overtime Adjustment."
[24] Data Request BRCS-WF-01-003.
[25] Response to Data Request BRCS-WF-03-013.
[26] Workpaper *A(3)_Correction Workpapers*, pp. 1-7, tab *C-3.17/C-3.18.*
[27] Response to Data Request BRCS-WF-03-018.
[28] Workpaper *A(3)_Correction Workpapers*, pp. 8-13, tab *C-3.23.*
[29] Response to Data Request BRCS-WF-01-003.
[30] Response to Data Request BRCS-WF-03-024.
[31] Workpaper *A(3)_Correction Workpapers*, pp. 14-18, tab *C-3.30.*

the Company's filing. Those errors are as follows: a typographical error on Schedule C-3.1 that understates the adjustment by $20;[32] a credit adjustment made to Account 930.2 instead of 921;[33] an error that understates 2002 Retained Earnings by $103,552;[34] an adjustment made to Account 333 instead of Account 332;[35] errors for the average service life of Account 329 (Other Structures)[36] and Account 390 (Structures & Improvements – Other)[37]; minor errors to historical data for Dominion Resources, Inc.;[38] a number of errors in the E-4.1 schedules, which develop annualized test year revenues at proposed versus current rates;[39] an error calculating projected "Notes Payable – Money Pool";[40] and an error in the weighted average cost of debt for the projected period of 2008-2010.[41]

Furthermore, Blue Ridge was unable to confirm the accuracy of a few inputs to the Company's revenue requirement model. First, Blue Ridge was not able to verify the current accrual rate and average service life for Miscellaneous Intangible Plant – Computer Software (Account 303) on Schedule B-3.2 Current (page 6). The current accrual rate for Account 303 on the schedule in the Company's filing is 12.87 and the average service life is 10 years.[42] The accrual rates on Schedule B-3.2 are discussed at page 4 of Sylvia Green's direct testimony, where she explains that "the current depreciation accrual rates used by DEO became effective January 1, 2001 as approved by the Commission in Case No. 01-2592-GA-18 UNC, with the exception of the accrual rate for Account 303.03, Miscellaneous Intangible Plant, which became effective January 1, 2003 as approved by the Commission in Case No. 03-2204-GA-AAM." The documentation provided by the Company to support the current accrual rates and average

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[32] Response to Data Request BRCS-WF-01-003, part 1. This does not impact the filing because it is offset.
[33] Response to Data Request BRCS-WF-01-003, part 3. This does not impact the filing because total O&M expenses are correct.
[34] Standard Filing Requirement, Schedule C-11.1, line 6, 2002 Column.
[35] Workpaper *A(3)_Math.Accuracy Test.zip*, Schedule B-3, p. 1 of 7, lines 9 and 10. This error has no impact on the filing because total Production & Gathering Plant on line 15 is correct.
[36] Standard Filing Requirement, Schedule B-3.2 Current, p. 1 of 7, line 8.
[37] Standard Filing Requirement, Schedule B-3.2 Proposed, p. 5 of 7, line 4.
[38] Workpaper *A(3)_Math.Accuracy Test.zip*, Schedule PCD-5, p. 2 of 3, lines 2 and 3, notes 3, 4 and 6 and p. 3 of 3, lines 11 and 12, note 6(a).
[39] Workpaper *A(3)_Math.Accuracy Test.zip*, Schedule E-4.1 GSS, p. 10 of 18, line 27, note 7; Schedule E-4.1 GSS Res, p. 4 of 18, note 10; Schedule E-4.1 GTS, p. 17 of 18, Column E, note 4; Schedule E-4.1 GTS, p. 11 of 18, note 4; Schedule E-4.1 GTS, p. 5 of 18, Column E, note 3; Schedule E-4.1 LVGSS, p. 10 of 18, line 35, note 4; Schedule E-4.1 FSS, p. 1, Column C Line 3, note 1; and Schedule GTS-N, p. 5 of 6, line 5, note 2. Tracing the dependents/precedents of these numbers shows that they do not impact the outcome of the Company's filing.
[40] Standard Filing Requirement, Schedule F-4A, line 8 "Notes Payable – Money Pool": this amount is calculated by subtracting short term debt at Company-proposed rates from short term debt at current rates. Due to an error, this number was overstated by $39,708. Schedule F-4a does not impact the revenue deficiency included in the Company's filing.
[41] Standard Filing Requirement, WPG-3, lines 4 and 7. The 3.24% on WPG-3 was based on an early version of Schedule PCD-1. This number changed to 3.28% in Dominion's revised schedule, but WPG-3 was not changed to reflect the revised weighted average cost of debt. WPG-3 does not impact the revenue deficiency included in the Company's filing.
[42] Standard Filing Requirement, Schedule B-3.2 Current, p. 6 of 7, Cols. F and I, line 2.

service lives on Schedule B-3.2 Current[43] shows that the 2001 accrual rate for this account was 10 and the average service life was 10 years, and that in 2003 these were changed to an accrual rate of 6.67 and an average service life of 15 years.[44] Neither the accrual rate nor the average service life shown in the Company's filing corresponds to the Commission's 2003 entry addressing them. Second, Blue Ridge was unable to verify the accuracy of the Company's PIPP Revenues on line 2 of Revised WPB-5.1.[45] Blue Ridge issued data request BRCS-WF-04-005 part 12, seeking supporting documentation for this number (among others) on WPB-5.1. The Company's response indicated that DEO had provided information to Staff to support its cash working capital allowance, and suggested obtaining answers to Blue Ridge's questions from Staff.[46] Though Blue Ridge's follow-up discussions with Staff assisted in answering most questions Blue Ridge had on WPB-5.1, these discussions did not produce a Company source for the test year PIPP revenues on line 2. This number impacts the Revenue Lag Allowance, the Total Cash Working Capital, the Working Capital Allowance, the Rate Base, and ultimately, the calculated revenue deficiency. Third, Blue Ridge was unable to reconcile some of the Company's depreciation schedules to the Company's FERC Form 2s. Specifically, the depreciation schedules in *Supplemental #21 B-3.3 – Combined 1997-2007_Rev.xls* for years 1997-2001 were not reconciled to the Company's FERC Form 2s for those years. Blue Ridge issued data requests for the purposes of tying out the Company's depreciation schedules in Supplemental #21,[47] and with the Company's responses, Blue Ridge was able to reconcile years 2002-2007 to the FERC Form 2s. Initially, Blue Ridge did not believe it was necessary to issue requests for reconciliations for all of these years (1997-2007), and instead anticipated being able to use the Company's responses to discovery as a guide to tie out the depreciation schedules for earlier years. However, after receiving the Company's responses, Blue Ridge discovered that the reconciliation for one year may not necessarily serve as a guide for reconciling other years. Blue Ridge requested a reconciliation for the years 1997-2001, and at the time of the writing of this report, the Company was working on providing those reconciliations to Blue Ridge.

Blue Ridge developed a Microsoft Excel-based model, which constitutes the workpapers associated with verification of the revenue requirement. This model—A*(3)_Math.Accuracy Test.zip*—provides the results of Blue Ridge's validation and verification process in accordance with the color code/comment system discussed above. Also, included in this model is a description of the corrections listed above in Blue Ridge's exceptions list. The comments and color-coding system used in these workpapers identifies the noted exceptions and describes the impact on the Company's

[43] Dominion East Ohio Gas Company Accrual Rates Summary, Table I.
[44] See Application of Dominion East Ohio, Case No. 03-2204-GA-AAM, Exhibit A, Proposed Depreciation Accrual. See also, Order in Case No. 03-2204-GA-AAM, paragraphs 5 and 7 and ordering paragraphs.
[45] The PIPP revenues amount is $123,385,458. *See,* Workpaper *A(3)_Math.Accuracy Test.zip,* Folder: Revised Schs, Filename: *WPB-5.1 Cash Working Capital.xls,* line 2.
[46] Response to Data Request BRCS-WF-04-005(12).
[47] See data request BRCS-WF-07-004 and BRCS-WF-07-004 Supplemental.

filing of correcting the errors. The impact of the corrections to the model on the Company's rate filing is summarized in the following table:

Table 1: Summary of the Impact of Corrections to the Company's Revenue Requirement Model[48]

Description of Correction	Location in Model	Impact on Revenue Deficiency	
Cost of Removal	B-3.1, p. 2	$344,503	Increase
Benefits	WPB-5.1	$33,078	Increase
Deferred Income Taxes for Depreciation	B-6, p. 1	($115,703)	Decrease
Purchased Gas Cost Adjustments	C-2.1	($266,507)	Decrease
Other Reconciling Items	C-4, p. 1	($91,287)	Decrease
Other Reconciling Items	C-4, p. 1	($36,404)	Decrease
Annualization of Merit and Wage Increases	C-3.17	$68,319	Increase
Payroll taxes	C-3.18		
Public Relations Expense	C-3.23	($66,403)	Decrease
Weatherization Funding	C-3.27	($518,270)	Decrease
Other Post Employment Benefits	C-3.30	($218,211)	Decrease
Cumulative Impact		**($866,885)**	**Decrease**

Audit Verification and Flow-Through of the Company's Revenue Requirement Model

DEO's revenue requirement model compiles a significant amount of data from various sources that, through a series of calculations, rolls up into the revenue requirement calculated by the Company. This serves as the basis for the Company's proposed rate increase. A key to auditing the Company's filing is to trace the source documentation through the model to ensure that it flows through the model's calculations properly. In an Excel-based model like the one used by the Company, source values can be linked throughout the model, so that they can be traced when the value is used elsewhere in the model or in a formula in the model. Blue Ridge found a number of instances in which the Company had hard-coded numbers into the model[49] that were derived elsewhere in the model itself or that resulted from calculations in other supporting schedules outside the model that could have been linked via formulas throughout the revenue requirement model. This would have eliminated actual and potential data entry errors, and it would have allowed Blue Ridge to verify all relevant inputs and assumptions more efficiently using the audit tools within Microsoft Excel. One example of this is Schedule C-3.16 provided above in the description of the color code system. The number on line 1 is calculated on Schedule C-2.1, which is another tab in the revenue requirement model.[50] Rather than linking C-3.16 to C-2.1, the Company hard-coded the number into Schedule

[48] Response to Data Request BRCS-WF-01-003 and Workpaper *A(3)_Correction Workpapers.pdf.* Workpaper *A(3)_Math.Accuracy Test.zip*, filename *C3 and C3.1.xls*.

[49] *That is, the Company either typed a number into a cell or copied and pasted a value (as opposed to a link)* into a cell, rather than linking to the number where it appears elsewhere in the model.

[50] Standard Filing Requirement, Schedule C-2.1, p. 8, line 9.

C-3.16. In this example, although not linked, the Company did provide a source on C-3.16, which allows for a manual verification check. However, verification becomes even more complicated when a number is hard-coded in the model and no source is provided. For example, the "Notes Payable – Money Pool (Net)" on line 8 of Schedule F-4A is a hard-code with no source provided. Through discussions with the Company, Blue Ridge determined that the number on line 8 is an error and that this number should have been $16,653,542 – which is calculated by netting the Short Term debt (current) amount on Schedule F-3 and the Short Term debt (proposed) amount on Schedule F-3A. If the Company would have used linking to calculate this number, this calculation would have been transparent for auditing purposes (i.e., data requests and follow-up questions would have been avoided) and the error in the model related to this hard-code could have potentially been avoided. It should be noted that the Company did link many values in the model and did not hard-code all values. However, the transparency of the Company's revenue requirement model could be improved and the auditing of the Company's model could be streamlined with better use of linking throughout the model.

Conclusions and Recommendations

The mathematical errors discovered by Blue Ridge overstate the revenue deficiency by $866,885. Blue Ridge recommends that Staff propose an adjustment to the Company's filing and that the Company incorporate into their model the corrections and updates listed above.

Blue Ridge also recommends that the Company be required to explain and/or correct the accrual rate and average service life for Account 303 Miscellaneous Intangible Plant – Computer Software that was not verified in relation to the supporting documentation provided by the Company. In addition, the Company should provide an explanation and/or supporting documentation for the PIPP Revenues on Revised WPB-5.1.

For future rate cases, Blue Ridge also recommends that the Company maximize the use of formula linking within the electronic revenue requirement model to streamline the review process and minimize errors in data input.

General Requirements Task A.4

Task A.4-Review the Staff Report of Investigation in the Applicant's last base rate case.

Blue Ridge reviewed the Staff Report of Investigation in the Applicant's last base rate cases for West Ohio (i.e., 82-1458-GA-AIR). The Auditors concluded that there were no significant carry over issues from that case. Blue Ridge did not review the last Staff report related to the last East Ohio rate case. The review regarding the last East Ohio rate case focused on the Commission's Order in 93-2006-GA-AIR. General Requirements Task A.5 includes a list of compliance issues and the Company's action/response to each issue from that case.

General Requirements Task A.5

Task A.5-Review the Opinion and Order from the Applicant's last base rate case.

Blue Ridge reviewed the Opinion and Order from the Company's last base rate case (93-2006-GA-AIR). A list of compliance issues are included in the workpapers in the file labeled *A(5) Compliance Issues Last Case.doc* along with the Company's action/response to each issue. Blue Ridge did not identify any carryover compliance issues that affect this rate case.

General Requirements Task A.6

Task A.6-Review the audit report and Opinion and Order from the Company's most recent gas cost recovery case.

The audit report from the Company's most recent gas cost recovery case (Case No. 07-0219-GA-GCR) and the Opinion and Order were reviewed. The Management and Performance Audit of Gas Purchasing and Policies of East Ohio Gas Company, performed as part of the gas cost recovery case, noted two conclusions related to the current rate case. One conclusion states that the current rate case provides an opportunity for the review of DEO's current storage assignments. While Blue Ridge did tie the value of storage on the Company's books and records to FERC Form 2, the storage assignments issue is a regulatory one, beyond the scope of this audit. The other conclusion was related to the equitability of collection of discounts on fuel retention charges. As a policy issue, this conclusion is also beyond the scope of this audit. Therefore, no crossover issues from the most recent gas cost recovery case are relative to the audit of this rate filing.

General Requirements Task A.7

Task A.7-Develop a comparison of the revenue requirement from the Opinion and Order in the last base rate case to the current revenue requirement (pro forma) in the current case, to assist in identifying what costs are driving the requested increase.

Blue Ridge reviewed the revenue requirement from the last base rate case[51] and compared it to the revenue requirement in the current case.[52] The following is a comparison of the Standard Filing Requirement Schedule A-1 for the two cases with variances identified.

[51] Response to Data Request BRCS-DWS-05-007 (Case No. 93-2006-GA-AIR).
[52] Standard Filing Requirement, Schedules A1, B1, B2, C1, C2.

Table 2: Revenue Requirements Comparison[53]
Schedule A-1

	Description	93-2006-GA-AIR LAST CASE	07-0829-GA-AIR CURRENT CASE	07-0829-GA-AIR CURRENT CASE Revised - Murphy	VARIANCE Dollars	VARIANCE Driver
1	Jurisdictional Rate Base	760,043,981	1,071,881,705	1,071,769,127	$ 311,725,146	Plant Asset increase primarily Distribution
2	Net Operating Income	14,957,608	46,206,661	46,392,944	$ 31,435,336	Rev down 7.5% while Exp down 11%
3	Rate of Return - Earned	1.97%	4.31%	4.33%		
4	Rate of Return Requested	11.09%	8.59%	8.59%		
5	Required Operating Income	84,288,878	92,074,638	92,064,968	$ 7,776,090	
6	Operating Income Deficiency	69,331,270	45,867,977	45,672,024		
7	Gross Revenue Conversion Factor	1.63140	1.6151830	1.6151830		
8	Revenue Deficiency	113,107,033	74,085,177	73,768,677	$ (39,338,356)	
9	Revenue Increase Requested	98,901,903	75,007,378	75,007,378	$ (23,894,525)	
10	Adjusted Operating Revenues	1,139,211,256	1,053,896,931	1,053,896,931	$ (85,314,325)	Revenue decreased primarily in Gas Costs
11	Revenue Requirements	1,238,113,159	1,128,904,309	1,128,904,309	$ (109,208,850)	
12	Percent Increase	8.68%	7.12%	7.12%		

General Requirements Task A.8

Task A.8-Interview the Applicant's management personnel and review both internal and published financial reports to assure understanding of the Applicant's operation and organization.

Interviews were conducted with the Company's management personnel to review both the internal and published financial reports and to understand and verify the processes in place that led to the development of the rate application documents. The following table contains the names of the Company personnel interviewed, their respective titles and the subject matter covered. Interview summary notes are included within the workpapers.

Table 3: Company Personnel Interviewed

#	Name	Title	Subjects
1	Bruce Klink	President – Dominion East Ohio	Budget process and Rates
2	David Searles	Vice President – Dominion East Ohio	Capital Budget process, Construction program planning and Rates
3	Jay Briggs	Director - Internal Audit	Internal Audits, process, results, follow-ups
4	Greg Sciullo Karen Worcester	Director of Accounting Manager of Accounting	Case Development, Validation of Case Information, Capital Planning & Budget, Shared Services - Cost and Management, & Budget Process
5	Sylvia Green Lou Ann White	Manager of Fixed Asset Accounting Supervisor Fixed Asset Accounting (Pittsburg)	Preliminary Interview Fixed Asset System – Work Order Process
6	Abby Corbin Joyce Laley	Manager Finance and Business Services Sr. Financial Analyst for Finance and Business Services	Budget Process
8	Pam Culp Beck Merritt Eric Bauer Larry Rice	IT Project Manager for CCS Director of Customer Billing & Payment IT Systems Analyst Senior Transportation Analyst	Billing, Revenue Validation, and Tariffs
9	Carrie Fanelly	Director of Customer Service Centers	Billing, Revenue Validation, and Tariffs

[53] Workpaper *A(7) BRCS – Rev Req Comp.xls.*

#	Name	Title/Position	Subjects
10	James Ferrara Larry Carter	Director, Supply Chain Management Manager, Corporate Disbursements	Capital Project Invoicing and Payment, Accounts Payable Policies and Procedures
11	Mark Wanstreet Rose Cyprowski	Director of Supply Chain Mgt Manager – Supply Chain Services	Supply chain, materials and supplies and warehouse operations
12	Mark Stevens Garrett Clarke	Supv – Supply Chain (Purchasing)	Supply Chain, materials and supplies
13	Jeff Murphy Vicki Friscic	Director, Regulatory and Pricing – Dominion East Ohio	Budget Process and Rates
14	Larry Rice	Retail Transport Analyst Sr. Transporation Analyst, Transportation Services Dept. – Dominion East Ohio	Load Forecasting Standard Filing Requirement Model & Operational Data
15	Sylvia P. Green Lou Ann White	Manager of Fixed Asset Accounting Supervisor Fixed Asset Accounting (Pittsburg)	Fixed Asset System – Work Order Process
16	Katherine Bond Nancy Fines	Director of Financial and Business Services Supply of Service Company Accounting & Benefits Accounting	Service Company Allocations; Budget Process
17	Keli Morrison Nancy Fines Kelly Conway Dorothy Gerena Trisha Cassidy Katarina Stevens	Director of Accounting- Corporate Accounting Dominion Resource Services – Supervisor, Accounting Dominion Resource Services – Supervisor, Accounting Dominion Resource Services – Lead Account Dominion Resource Services – Service Company Dominion Resource Services	Development of Service Company Allocators / Budget Process
18	Jackie Edwards Willie Oliver Carol Hurst Joyce Laley	Sr. Business Performance Analyst Sr. Account HR Specialist Sr. Financial Analyst for Finance and Business Services	Payroll Expense Development & Headcount Data
19	Joyce Laley	Sr. Financial Analyst for Finance and Business Services	Budget Process
20	John Schniegenberg Brent Breon	Principal Engineer Mgr. Planning and Revenue Growth	Capital Project Engineering, procurement and construction
21	Frank Martin	Area Engineer	Capital Project construction and maintenance

General Requirements Task A.9

Task A.9-Issue data requests for information to complete the following specific items. Each of these items will be review and incorporated within the analyses, findings and conclusions related to our assessment of the accuracy and validity of the Company's filing.

Blue Ridge submitted 281 data requests during this project. With Staff's concurrence, Blue Ridge's document management system was used to track the data requests and responses. A complete listing of all the data requests is provided in Appendix 2 and copies of the provided responses to the data requests are included in the workpapers to the report.

Blue Ridge reviewed documents to understand the overall management of the Company and to conduct tests of accuracy of information contained within certain records. The following is a topical list of the information reviewed. Any findings related to these areas are discussed in its appropriate section.

Table 4: Company Filing Subject Areas Reviewed for Accuracy and Validity

#	Item	Data Request
1	Actuarial reports for pensions and other than pensions	GPR-1-004 WF-03-024
2	Affiliate Agreements for Inter-affiliate Transactions	GPR 01-005
3	Audit Committee Minutes	GPR-01-006
4	Billing Records (registers, etc.)	GPR-01-007
5	Board of Director Minutes	GPR-01-008
6	Chart of Accounts and Accounts Manual	GPR-01-001 (Supp #31) GPR-01-009
7	Construction Work Orders	MTD 03-01, et.al.
8	Construction Budgets	MTD 03-01 – sample projects
9	Continuing Property Record (CPR)	MTD 03-01 – sample projects
10	Corporate Budget by Month and by Function	WF-01-008 WF-01-013
11	Current Labor Contract	GPR-01-013
12	External Independent Audit Reports and Workpapers	GPR-01-014
13	Franchise Fee Records (collection and payment)	GPR-01-015
14	Forecast Assumptions	HS-01-001 HS-01-002 HS-01-004 HS-01-005 HS-01-006 HS-01-008 HS-01-009 HS-01-010 HS-01-011 HS-01-012 HS-01-013 HS-01-014 HS-05-001 HS-05-002 HS-05-003 HS-05-004 HS-05-005
15	General Ledger and Subsidiary Ledgers	GPR-01-017 MTD-01-001 WF-01-013 WF-03-011
16	Income Tax Returns	GPR-01-018
17	Internal Audit Reports and Workpapers	GPR-01-019
18	Invoices	MTD 03-01

#	Item	Data Request
19	List of Property Units	MTD 03-01
20	FERC General Advertising Expense Acct. 930.1	GPR-01-022
21	FERC Miscellaneous General Expense Acct. 930.2	GPR-01-023 GPR-01-001
22	Monthly or Quarterly Operating/Financial Reports	GPR-01-024
23	Monthly or Quarterly Trial Balances	GPR-01-025 WF-01-013
24	Monthly Sales by Rate Schedule and/or Customer Class	HS-01-005 HS-01-007 HS-01-008 HS-01-012 HS-05-003 HS-05-005 WF-01-016 WF-01-017 WF-01-018 WF-02-009 WF-02-010
25	Organizational Charts (corporate and internal reporting lines and departments)	GPR-01-027
26	Payroll Records	GPR-01-028
27	Property Tax Statements	GPR-01-029
28	Risk Committee Minutes and Documentation	GPR-01-030
29	Sample of Customer Bills (to verify rates and information)	GPR-01-031
30	Standard Journal Entries	GPR-01-032 MTD-01-029

B. OPERATING INCOME

Audit Team

1. Warren Fischer, CPA – Lead
2. Patrick Phipps
3. Howard Solganick
4. James Webber
5. Hallie Lawrence
6. Tracy Mullinax – Support

Audit Objectives and Scope

Blue Ridge's audit objectives and scope as provided in the approved work plan included an evaluation of the following:

> *Task B.1-Prepare an operating income comparison of the test year to actual historical financial data. The comparison shall contain data for the five most recent historic years for which data is available to help determine whether the test year operating income is representative of historical trends. Abnormalities of the test year will be noted and investigated.*
>
> Develop a comparative analysis. Determine any potential non-recurring/one time expenses. Request support for/or explanation of any potential non-recurring expenses.
>
> *Task B.2-The auditor selected shall obtain through records, trial balances, or informational requests to the utility, a side-by-side spreadsheet of financial and operational monthly data for the twelve months of the test year. From this analysis, the auditor shall create a list of items to be further examined by obtaining invoices, payroll records, work orders, supporting budget documentation or other source documents.*
>
> Develop a comparative operational indicator analysis using accepted comparative analysis such as cost per customer, cost per employee, etc. Develop a list of potential issues requiring further review.
>
> *Task B.3-The auditor selected shall work with Staff and develop an investigation audit plan directed at the significant issues of the case*
>
> Prepare an outline of a significant issue audit plan. Meet with Staff to discuss audit plan. Finalize audit plan.
>
> *Task B.4-Compare the final approved budget to five actual, historical years to determine whether the test year budgeted information is representative of historical trends. Abnormalities of the budget shall be noted and investigated.*

Review 2007 budget and compare to actual results for the previous five years. Request and review significant budget changes and the underlying reasons. Request and review company responses to data requests concerning the budget and significant budget variances.

Task B.5-Document the budget process

Request and review the company's budget procedures. Request company to provide a flow chart of the budget process noting the level of management approval required at various decision points and any deviations from accepted norms.

Task B.6-Interview Company personnel responsible for the compilation of the budgeted information

Interview the senior executive and manager responsible for the budget process to understand fully the Company's budget process and how priorities are established within that budget process.

Task B.7-Interview a select sample of company personnel (function heads) that had input into the budget and track their input through the budget process.

Interview the select senior executive and operational managers responsible for the budget process to access the how individual department budgets are completed and more fully understand the Company's budget process and how priorities are established within the budget process.

Task B.8-As actual information for the budgeted months becomes available, compare and analyze budgeted months to actual months. Significant variances shall be investigated.

Issue a standing data request for actual information as it becomes available for the test year. Update the budget vs. actual analysis for the test year. Issue data requests and review/assess responses on significant variances.

Task B.9-Compare most recent prior year budget to actual results and note significant variances.

Request budgeted data at sufficient level of detail to permit functional assessment of actual to budget. Understand any nuisances between FERC accounting and budgets. Create a budget to actual for previous budget year.

Task B.10-Prepare and analyze monthly test year and three historical years of monthly historical consumption data (sales) and customer count by tariff.

Request and review actual consumption for the test year and the last three years and customer counts by tariff. To the extent not electronically provided, create a spreadsheet with this data.

Task B.11-Review the Applicant's written summary explaining the forecasting (sales) methodology as it relates to the test year. (SFR Supplemental C-12).

Review the forecasting methodology, compare it to accepted industry norms and note any deviations.

Task B.12-Interview Applicant's personnel responsible for the sales forecast.

Request list of employees involved in sales forecast. Develop interview questions.
Schedule interviews with personnel involved. Issue interview summary reports from interviews.

Task B.13-Review the applicant's proposed adjustments to operating income and trace them to supporting workpapers and source data.

Request and review back-up documentation to any pro forma adjustments included in the filing. Mathematically validate calculations and source data cross reference. Prepare a back-up book of supporting data.

Task C.15-The auditor will review and analyze the Applicant's proposed adjustments to operating income and rate base and trace them to supporting workpapers and source data. [54]

Validate the company's revenue requirement calculations and linkage to backup supporting document and note any exception.

Background

In this section, the audit focused on the Company's operating income and the validity of the information contained in the income statement and revenue requirements model. Blue Ridge also reviewed the past trends in expenses and budgets to determine whether any anomalies or extraordinary issues impacted the revenues and/or costs included in the Company's filing.

To complete this analysis, Blue Ridge's team of certified public accountants, engineers, economists, and regulatory analysts evaluated DEO's operating income to determine whether the information contained in that filing can be relied upon by PUCO to set rates. Blue Ridge requested a significant number of source documents and explanations of processes and variances by means of over 100 data requests and traced inputs in the filing back to source documentation. Blue Ridge reviewed the organization charts included in the Company's filing and then obtained more current organization charts by department to understand the lines of responsibility for each process tested. The updated organization charts reflect the organizational structure of Dominion Resources, Inc. (DRI) after its October 1, 2007, realignment in which DRI completed its strategic

[54] Due to the similarities between Task B.13 and Task C.15, they will be discussed together in this report.

refocusing efforts and organized into three operating units: Dominion Energy, Dominion Virginia Power, and Dominion Generation. Blue Ridge validated information in the filing with source documentation and checked the validity of the revenue requirements model. Blue Ridge interviewed the Company's senior and operating level managers concerning how the information in the Company is validated.

Blue Ridge also interviewed numerous Company executives and managers about the budget process used to prepare the 2007 budget, which is the source for nine months of the test year data. Interviews covered the budget process timeline from inception during the strategic planning phase through senior management and Board of Director approval. The Company's 2007 departmental budget guidelines were evaluated, and the overall budget preparation and approval process was documented in a series of Company-prepared flow charts and timelines.

Blue Ridge examined in detail the Company's revenue requirement schedules included in its Standard Filing Requirements to verify and validate all inputs and calculations used to produce the test year values that comprise the Company's justification for a rate increase. This required numerous data requests to source hard-coded inputs as well as on-site work with DEO personnel to verify all inputs and assumptions.

Operating Income – Natural vs. FERC Accounting

Background

The Company uses a different Chart of Accounts for financial reporting purposes from the one used for regulatory purposes. This difference caused some difficulty in preparing the various comparisons of both the 2007 test year values and the 2007 budget to the prior five years of actual results required in Tasks B.1 and B.4. In the normal course of business, DEO maintains its financial records in a Chart of Accounts structure the Company calls "natural" accounts. This structure is Company-specific and is designed to work with DEO's SAP and Hyperion systems. An orientation meeting was held with DEO accounting personnel on December 18, 2007, at the beginning of the audit to obtain a working knowledge of the accounting processes and procedures used to track its operational and financial results. During that meeting the Company provided Blue Ridge a PowerPoint presentation explaining how no fewer than 12 SAP modules are utilized to operate the Company's business.[55] The SAP system was described as "an enabler of financial, supply management, HR and other processes" that provides "an integrated solution vs. a traditional systems approach."[56]

The Company utilizes the SAP Industry Solution for Utilities (IS-U Industry Solutions) module to produce internal cost management reports for regulated utilities while still

[55] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation).

[56] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation).

providing external reports for regulatory purposes.[57] The IS-U Industry Solutions module integrates data from four other SAP Finance modules to produce FERC-based financial statements.[58]

The Company explained that its "natural" Chart of Accounts provides income statements and balance sheets in a more traditional business format.[59] The SAP natural accounts for all balance sheet and revenue accounts are purportedly direct-mapped or converted to FERC accounts monthly to facilitate the preparation of the Company's regulatory financial reports.[60] Direct mapping can be on a one-to-one basis or a range of natural accounts mapped to a FERC account.[61] Certain operating expenses are not direct-mapped; instead, they are allocated to FERC accounts by natural account and cost centers or Work Breakdown Structure (WBS) elements via a process the Company calls the "tracing" method. The tracing method requires the assignment of FERC indicators to each cost center and WBS element.[62] The Company explained its accounting process in more detail as follows in response to discovery during the audit:

> Dominion East Ohio utilizes SAP software to maintain its General Ledger and record the majority of its transactions. SAP uses a "natural" Chart of Accounts. The major differences between the SAP natural chart of accounts and the FERC chart accounts are the numbering scheme and the categorization of the Operations and Maintenance Expense accounts. The numbering scheme in SAP supports a presentation in accordance with generally accepted accounting principles (GAAP). The majority of the Operations and Maintenance Expense accounts in SAP are resource oriented (labor, materials, contractor services, etc.) reflecting the nature of the transactions rather than being characterized by function as in the FERC Chart of Accounts.
>
> Each month, the General Ledger balances in SAP are converted to a FERC Chart of Accounts via either direct mapping of specific accounts (All Balance Sheet, Revenue, Gas Purchase Expense, Tax, Interest Expense and select O&M accounts) or a process called tracing which derives the FERC account based on a combination of natural account and cost center or WBS element (project number). Each cost center and WBS element are

[57] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation).
[58] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation).
[59] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation).
[60] For a copy of the SAP accounting presentation, see Sciullo Worcester - Interview on 071217 (Presentation). See also Response to Data Request BRCS-WF-03-032, and Sciullo & Worcester -Interview on 080107.
[61] Response to Data Request BRCS-WF-03-032.
[62] Response to Data Request BRCS-WF-03-032 and Sciullo & Worcester -Interview on 080107.

assigned FERC indicators that map costs to either a single FERC account or to multiple FERC accounts as appropriate.[63]

Analysis

DEO provided Blue Ridge trial balances and income statements in both the natural account and FERC account format.[64] As noted above, all natural balance sheet accounts, revenue accounts, and certain expense accounts, such as purchase gas expense, depreciation expense, non-operating income/expense, interest expense, and taxes, should map directly to a corresponding FERC account. Resource-oriented expenses are mapped to FERC accounts using a tracing methodology that incorporates FERC indicators in a table within its SAP system. In response to discovery issued to follow-up on FERC-mapping and tracing issues discussed during the interview with the Dominion Resources, Inc (DRI) Director of Accounting and Manager of Accounting supporting DEO, the Company provided the table of its direct mapping to FERC accounts and the table of its FERC indicators used to trace natural expenses to FERC accounts.

To test how well the FERC and natural account income statements to be used for the variance analyses required by Tasks B.1 and B.4 aligned, Blue Ridge compared the FERC and natural account income statements for the years 2002 – 2007. The Company's natural and FERC income statements resulted in the same net income amounts by month and year. However, differences may exist between total Operating Revenue and total Operating Expenses due to how revenue and expense is classified for GAAP and FERC reporting purposes. For example, income tax expense and deferred income tax expense is included above the line in Operating Expenses for FERC reporting and below the line for GAAP purposes. Additionally, inter-company transactions appear to be eliminated for FERC reporting purposes.

Findings

Blue Ridge found DEO's direct-mapping process confusing to replicate and noted that some of the natural accounts did not map to the corresponding FERC account according to the SAP direct map table provided in discovery. The following excerpt from the Company's 2007 natural account income statement for the year ended December 31, 2007, illustrates instances in which revenue is classified as Operating Revenue for internal reporting purposes and as a different category of revenue or other income and expense account for FERC-reporting purposes. Additionally, this excerpt identifies certain natural revenue account balances that do not agree to the FERC account to which they are supposed to be directly mapped. Since net income agrees between the natural and FERC income statements, this may indicate that the Company is making post-mapping adjustments to reclassify certain types of transactions to conform to certain FERC reporting requirements. However, it is not clear why the direct-mapping table would not already account for these requirements.

[63] Response to Data Request BRCS-GPR 01-009(i).
[64] Response to Data Requests BRCS-WF-02-013 and BRCS-WF-02-014.

Table 5: Direct Mapping Table[65]

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Total Company Actuals
For the Year 2007

			BLUE RIDGE CONSULTING SERVICES TESTING				
	MONTH	YTD 2007	FERC ACCOUNT (per FERC Direct Map Table)	FERC ACCOUNT CATEGORY	FERC BALANCE VIA REPLICATION OF DIRECT MAPPING PROCESS	ACTUAL FERC INCOME STATEMENT BALANCE	DIFFERENCE
	4111010 Res Gas-Billed	(464,440,712.87)	9480000	Operating Revenues	(464,099,285.87)	(464,095,555.11)	(3,730.76)
	4111020 Res Gas-Unbilled	341,427.00	9480000	Operating Revenues			-
	4112010 Com Gas-Billed	(128,287,986.71)	9481000	Operating Revenues	(139,697,616.88)	(139,697,616.88)	-
	4112020 Com Gas-Unbilled	(35,413.00)	9481000	Operating Revenues			-
	4113010 Ind Gas-Billed	(11,471,636.17)	9481000	Operating Revenues			-
	4113020 Ind Gas-Unbilled	97,419.00	9481000	Operating Revenues			-
	4113210 Migration Rider Rev	3,730.76	9483000	Operating Revenues	3,730.76	(22,758,721.80)	22,762,452.56
*	Regulated	(603,793,171.99)					-
	4220010 Non-Reg Gas Sales	(20,562,929.80)	9495000	Operating Revenues	(68,636,501.46)	(45,939,017.42)	(22,697,484.04)
	4220080 NR Gas Sales-Dom Ret	(5,595,792.00)	9495000	Operating Revenues			-
	5102010 COS - Natural Gas	213,225.87	9813000		799,457.45	1,659,288.30	(859,830.85)
*	Non-Regulated	(25,945,495.93)					-
**	Gas	(629,738,667.92)					-
	4117560 Oil Sales	(482,936.47)	9492000	Operating Revenues	(482,936.47)	(482,936.47)	-
*	Oil Production	(482,936.47)					-
	4117060 Prod Extr-Misc	(273,696.96)	9490000	Operating Revenues	(273,696.96)	(273,696.96)	-
*	Extracted Products	(273,696.96)					-
**	Other Energy-Related Commoditie	(756,633.43)					-
	4116230 Transm Facil-Nonaffi	-	9489200	Operating Revenues	-		-
	4116240 Rev Gas Trans-Com	(92,078,736.09)	9489300	Operating Revenues	(395,431,948.14)	(395,431,948.14)	-
	4116260 Rev Gas Trans-Ind	(47,580,923.69)	9489300	Operating Revenues			-
	4116270 Rev Gas Trans-OffSys	(1,460,954.22)	9489300	Operating Revenues			-
	4116280 Rev Gas Trans-Res	(253,278,185.03)	9489300	Operating Revenues			-
	4116281 Rev Gas Trans-D Troy	(102,324.11)	9489300	Operating Revenues			-
	4116282 Rev Gas Trans 1004	(930,825.00)	9489300	Operating Revenues			-
*	Gas Transportation	(395,431,948.14)					-
	4116314 Stor Gas Rev-Retail	(2,483,361.61)	9489400	Operating Revenues	(13,118,289.60)	(13,118,289.60)	-
	4116317 Stor Gas Rev DTI	(2,789,175.00)	9489400	Operating Revenues			-
	4116330 Stor Gas Rev-Nonaffi	(7,845,752.99)	9489400	Operating Revenues			-
*	Storage	(13,118,289.60)					-
**	Gas Transportation & Storage	(408,550,237.74)					-
	4115010 Forfeit Disc-Gas	(105,842.14)	9487000	Operating Revenues	(105,842.14)	(105,842.14)	-
	4115040 Misc Gas Serv Revs	(373,247.99)	9488000	Operating Revenues	(373,247.99)	(373,247.99)	-
	4305035 M&J & Contract Work	(356,296.00)	9415000	Other Income & Deductions	(707,327.23)	(356,296.00)	(351,031.23)
*	Service Revenues and Fees	(835,386.13)					-
	4118150 Oth Gas Rev-Misc	(1,560,102.21)	9495000	Operating Revenues			-
	4118165 Oth Gas Rev Firm Rec	(1,652,935.20)	9495000	Operating Revenues			-
	4118172 Pool & Meter-Dom Ret	(2,196,643.01)	9495000	Operating Revenues			-
	4118173 Pool & Meter-VPEME	(94.72)	9495000	Operating Revenues			-
	4118174 Pool & Meter-Troy	(9,602.93)	9495000	Operating Revenues			-
	4118180 Pool & Meter-Billed	(13,456,248.71)	9495000	Operating Revenues			-
	4118190 Pool & Meter-Unbill	(1,126.00)	9495000	Operating Revenues			-
	4118250 Royalties-Misc	(32,881.87)	9495000	Operating Revenues			-
	4118293 Special Deals-DomT	(46,290.04)	9495000	Operating Revenues			-
	4118294 SpecDls-VPEM Energy	(835,326.00)	9495000	Operating Revenues			-
	4118300 Special Deals-Nonaff	(5,127,678.46)	9495000	Operating Revenues			-
	4118320 Prod & Gath-Nonaffil	(17,558,850.51)	9495000	Operating Revenues			-
*	Other Miscellaneous Revenues	(42,477,779.66)					-
	4998000 Assoc Co Oper Rev	(351,031.23)	9415000	Other Income & Deductions			-
*	Inter-company Operating Revenue	(351,031.23)					-
**	Other Revenues	(43,664,197.02)					-
***	Operating Revenues	(1,082,709,736.11)					

Reconciling Operating Expenses is more complex than reconciling revenue (which is direct-mapped) as FERC indicators for certain resource-oriented expenses are added into the mix in addition to expenses that directly map to FERC accounts. On the balance sheet side, Blue Ridge could not tie total assets from the SAP financial statements to the FERC financial statements as of the date certain on March 31, 2007. In response to a

[65] Workpaper *B(Natural v. FERC Accounting)_IS actuals natural accts_2002-2007 by month.xls*, tab *2007*. The asterisks in the table are the Company's notations in its SAP natural account income statements. There are no specific definitions; however, it appears that one asterisk indicates a subtotal within a particular category, two indicates another level up on the hierarchy, and three means total revenue or expense.

data request, the Company indicates that a cost of removal and deferred tax adjustment were required to reconcile the two balances.[66]

Total Assets per SAP F/S	$ 2,859,348,570	
Regulatory Liability - Cost of Removal	(78,567,921)	Included in FERC account 108.0
Deferred Income Taxes	(14,834,002)	Included in FERC account 190.0
Total Assets per FERC F/S	$ 2,765,946,647	

These differences make account comparisons between FERC and SAP income statements difficult without Company-prepared reconciliations explaining the differences.

Because DEO's budget, test year, and actual results cannot be compared solely on a natural or FERC account basis, Blue Ridge concluded that the variance analyses required in Tasks B.1 (2007 test year to five prior years of actual) and B.4 (2007 budget to five prior years of actual) would not be comparable to one another. Instead, each analysis should be viewed as separate and distinct from the other comparative analyses.

Conclusions and Recommendations

For future rate case applications, the Company should provide reconciliations that tie the natural account income statements to the FERC income statements with explanations supporting all adjustments made outside the direct-mapping and tracing process to produce the FERC income statements.

Operating Income Task B.1

Task B.1-Prepare an operating income comparison of the test year to actual historical financial data. The comparison shall contain data for the five most recent historic years for which data is available to help determine whether the test year operating income is representative of historical trends. Abnormalities of the test year will be noted and investigated.

Background

Blue Ridge compared the unadjusted test year revenue and expenses filed by the Company with five prior years of actual results to identify unusual trends or variances in the test year values reflecting three months of actual results and nine months of budget results. Unadjusted test year values for 2007 were compiled from DEO's C-2 and C-4 schedules from its Standard Filing Requirements while prior year actual results for the period 2002 – 2006 were obtained from the Company's income statements by FERC account. DEO's budget data is typically prepared in natural account form only. However, the Company's 2007 budget for the months of April through December 2007 had to be converted to FERC accounts to prepare its test year revenue and expenses.[67]

[66] Response to Data Request BRCS-DHM-02-001.
[67] Response to Data Request BRCS-DWS-01-014.

Consequently, the comparison of the 2007 unadjusted test year to prior actual results for 2002-2006 was performed using FERC-based income statements. All schedules supporting the 2007 test year and 2002 – 2006 actual results were included within a single Microsoft Excel workbook. Material variances between the test year values and the average of the five prior years of actual results were submitted to the Company, which returned them with explanations.[68]

Analysis

To compare DEO's test year with prior years' actual results, Blue Ridge requested the Company's revenue and expenses by FERC account for the years 2002 through 2006. Because the Company's test year schedules in its Standard Filing Requirements was prepared in a different format from its historical income statements, Blue Ridge created a summary schedule by FERC account to synthesize the data from the two different sources. This summary by account organizes DEO's revenue and expenses according to (1) primary revenue or expense category, then (2) sub-category, and then (3) individual account description.

SAP FERC A/C	FERC	I/S Account Category	Category	Subcategory	Description

Test year 2007 amounts were then compared with the average of the five prior years at the individual account level. Blue Ridge identified specific accounts with variances representing an increase or decrease of greater than $1,000,000 and 20% over the 5-year average of historical results.

								MATERIALITY THRESHOLDS	
								1,000,000	20%
								TEST YEAR GREATER (LESS) THAN ACTUAL	
SAP FERC A/C	FERC	I/S Account Category	Category	Subcategory	Description	Unadjusted Test Year	Actual Results 5-Year Average	AMOUNT	%

Using account level data to identify material variances resulted in variances attributable to test year values being recorded in different accounts from historical book results. Consequently, Blue Ridge created a higher level summary worksheet as an alternative which summarizes revenue and expenses at the subcategory level noted above. The auditors then asked the Company to explain the material variances identified at the subcategory level. If the subcategory level of granularity was not sufficient to explain the variance adequately, the Company was asked to go down to the account level to explain the variance.[69]

[68] Response to Data Request BRCS-WF-06-001 and Workpaper *B(1)_WF 06-01 Variance between Test Year and 5 Year Actuals.xls*.
[69] Data Request BRCS-WF-06-001(a).

Blue Ridge also requested from the Company information related to any one-time, non-recurring expenses in the test year. DEO responded that it has excluded any nonrecurring, one-time, abnormal or extraordinary expenses from the test year through the Schedule C-3 adjustments in its Standard Filing Requirements schedules.[70]

Findings

Comparison of the projected test year to the average of the five prior years of actual resulted in the following. Nine of the 23 subcategories reflected variances exceeding $1,000,000 and 20% over the average of the period 2002-2006. However, many of these variances offset one another. For example, test year retail revenue is less than the 5-year historical average by $153 million or 18% while other operating revenue exceeded the 5-year average by $140 million or 46%, resulting in a net decrease in test year revenue compared with the 5-year average of $13 million. According to the Company, the offsetting variances are primarily due to the migration of retail sales customers to the Energy Choice program in which they purchase natural gas commodity service from other third party suppliers.[71]

Test year operation and maintenance expenses are less than the 5-year historical average due primarily to the reduction of gas purchase costs associated with the migration of retail customers to the Energy Choice program ($191 million) offset by an increase in bad debt expense of $94 million over the 5-year historical average caused by higher commodity prices and an increase in the number of customers in the Percentage Income Payment Plan (PIPP).[72] Consistent with the analysis of shared service cost allocations from Dominion Resources Services, Inc. (DRS) to DEO in FERC Account 923, Blue Ridge noted an increase in test year administrative and general operations expenses of $7 million over the 5-year historical average due to increased DRS charges allocated to DEO.[73] The primary reasons for the increase are increases in four service categories: (1) Executive/Administrative Compensation, (2) Customer Service, (3) Miscellaneous and (4) Information Technology. Blue Ridge's analysis of this increase is addressed in more detail in the section Rate Base Task C.16 of this report.

Conclusions and Recommendations

The 2007 test year revenue and expenses do reflect some significant variances from the 5-year historical average. However, the changes in the Company's test year operations appear to be explained adequately by the Company. Accordingly, Blue Ridge confirmed that the Company did not have any non-recurring, abnormal or extraordinary expenses that were not explained adequately through discussions and data responses.

[70] Response to Data Request BRCS-WF-01-014.
[71] Workpaper *B(1)_WF 06-01 Variance between Test Year and 5 Year Actuals.xls*, tab Summary by Category.
[72] Workpaper *B(1)_WF 06-01 Variance between Test Year and 5 Year Actuals.xls*, tab Summary by Category.
[73] Workpaper *B(1)_WF 06-01 Variance between Test Year and 5 Year Actuals.xls*, tab Summary by Category.

Operating Income Task B.2

Task B.2-The auditor selected shall obtain through records, trial balances, or informational requests to the utility, a side-by-side spreadsheet of financial and operational monthly data for the twelve months of the test year. From this analysis, the auditor shall create a list of items to be further examined by obtaining invoices, payroll records, work orders, supporting budget documentation or other source documents.

Background

To obtain a complete picture about the operations of the Company, it is important to examine both financial and operational data. Examining one or the other in isolation may not necessarily provide sufficient context whereby the Company's operations may be fully understood and a proper perspective of the Company's revenues, expenses and operating income may be gained. Therefore, for this task, Blue Ridge requested both operational and financial data pertaining to the test year and the five years prior to the test year, summarized in Workpaper *B(2)_Operational Data Comparison.xls* and comprising comparative analyses, including employee and customer counts, sales volumes and financial data.

Analysis

To analyze DEO's financial data, Blue Ridge requested the Company's revenue and expenses by account for the years 2002 through 2006 in the same format as the test year data.[74] As described in the section Operating Income Task B.1 above, Blue Ridge performed an initial review of the test year data versus the average of results for the years 2002 through 2006 at the account level.[75] The auditors also obtained and analyzed employee and customer related data for the years 2002 through 2006 so that trends in these data could be identified and examined and data could be used to develop per customer and per employee revenue, expense, and income statistics.

DEO's responses to discovery related to employee counts contributed to the development of the table below, which provides employee counts by month throughout the relevant time periods.[76] This table shows that average monthly employee counts declined each year during the years 2002-2006, but increased in 2007. This table also shows that the Company projected a 3.0% increase in the average monthly headcount for the 2007 test year over 2006. However, the actual monthly headcount for 2007 was only 1.8% greater than 2006, even though the headcount at the end of 2007 was greater than the test year projected headcount at year-end. This is due to the "lumpy" nature of the headcount increase that occurred during 2007 in which a significant portion of the headcount additions took place in December 2007. This caused the average monthly headcount for the test year to exceed the actual average monthly headcount for 2007.

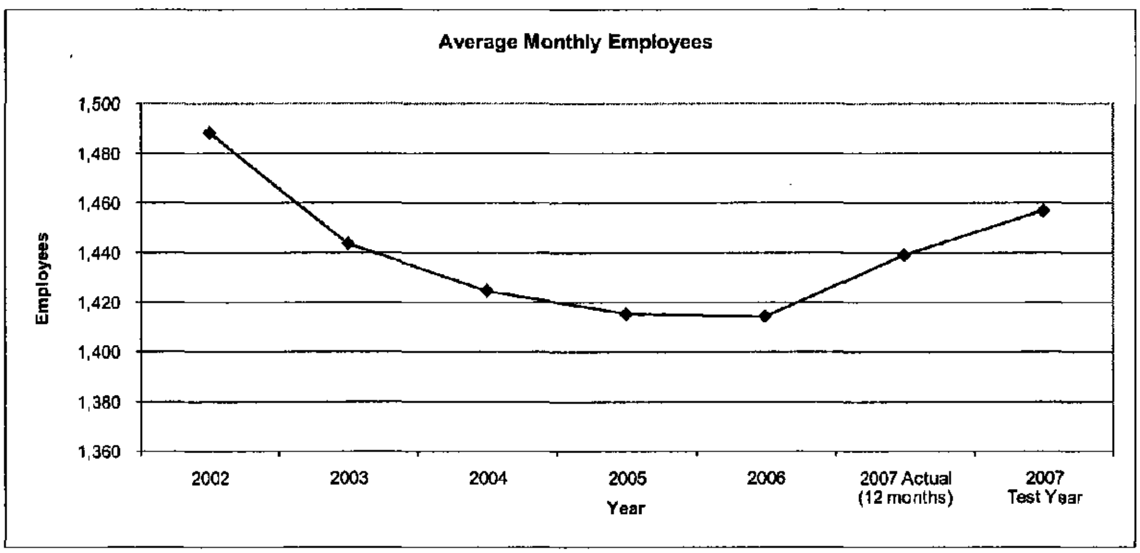
[74] Data requests BRCS-WF-01-009 and BRCS-WF-02-014. *See* Appendix 2.
[75] Workpaper *B1 Variance between Test Year and 5 Year Actuals.xls.*
[76] Workpaper *B(2)_Operational Data Comparison.xls,* Tab *Employees.*

Table 6: Active Employee Count 2002-2007[77]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Total Employees
2002 through 2007

	2002	2003	2004	2005	2006	2007 Actual (12 months)	2007 Test Year	Average 2002 - 2006
January	1,528	1,438	1,435	1,425	1,426	1,417	1,417	1,450
February	1,518	1,436	1,432	1,417	1,424	1,423	1,423	1,445
March	1,515	1,439	1,432	1,415	1,426	1,428	1,428	1,445
April	1,486	1,440	1,431	1,415	1,423	1,430	1,470	1,439
May	1,486	1,453	1,430	1,414	1,411	1,437	1,470	1,439
June	1,483	1,452	1,428	1,411	1,400	1,435	1,468	1,435
July	1,481	1,447	1,430	1,411	1,396	1,438	1,468	1,433
August	1,480	1,449	1,424	1,413	1,402	1,437	1,468	1,434
September	1,472	1,444	1,418	1,408	1,406	1,447	1,467	1,430
October	1,473	1,443	1,411	1,415	1,412	1,440	1,467	1,431
November	1,470	1,440	1,411	1,419	1,424	1,454	1,467	1,433
December	1,468	1,441	1,413	1,418	1,420	1,481	1,467	1,432
Average Monthly	**1,488**	**1,444**	**1,425**	**1,415**	**1,414**	**1,439**	**1,457**	**1,437**
Percent Change From Prior Year		**-3.0%**	**-1.3%**	**-0.7%**	**-0.1%**	**1.8%**	**3.0%**	

Figure 2: Average Monthly Employee Counts 2002-2007[78]



Since DEO's 2007 average monthly headcount was less than the test year average monthly headcount, Blue Ridge initially suspected that test year labor expense may be overstated. Blue Ridge followed up on this issue through discovery and found that test year labor expense is not overstated. In response to data requests which updated DEO's

[77] Workpaper *B(2)_Operational Data Comparison.xls*, Tab *Employees*.
[78] Workpaper *B(2)_Operational Data Comparison.xls*, Tab *Employees*.

C-9 payroll schedules with 12 months of actual 2007 results,[79] Blue Ridge noted that 2007 salary and hourly payroll costs exceeded test year payroll costs by approximately $6 million ($98 million[80] vs. $92 million[81]) or 7%. In response to an informal inquiry on the reasons for the increase in actual labor costs over plan, DEO provided a reconciliation of its test year labor costs to actual labor costs.[82] Actual labor costs increased over plan due to unplanned bonuses and severance costs. Since these one-time costs were not included in test year expenses, no adjustment to test year expenses is warranted.

The table below comprises actual monthly customer counts as well as the associated growth rates from 2002 through the test year. These data indicate customer counts have been relatively stable over the time period of 2002-2007.

Table 7: Customers by Month 2002-2007[83]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Non Storage Customers by Month
2002 through 2007

	2002	2003	2004	2005	2006	2007 Actual (12 months)	2007 Test Year	Average 2002 - 2006
January	1,223,707	1,225,290	1,228,727	1,231,195	1,226,147	1,223,868	1,223,760	1,227,013
February	1,224,592	1,226,942	1,229,270	1,232,053	1,227,319	1,225,652	1,225,543	1,228,035
March	1,224,346	1,225,401	1,227,664	1,231,312	1,226,363	1,223,763	1,223,639	1,227,017
April	1,222,260	1,221,177	1,223,419	1,226,487	1,223,626	1,220,013	1,219,903	1,223,394
May	1,216,858	1,215,442	1,215,532	1,219,920	1,217,388	1,211,130	1,213,365	1,217,028
June	1,208,075	1,210,830	1,209,431	1,212,089	1,212,214	1,205,641	1,206,881	1,210,528
July	1,203,219	1,205,587	1,206,025	1,207,335	1,207,033	1,198,001	1,202,213	1,205,840
August	1,199,698	1,202,342	1,204,336	1,203,985	1,201,482	1,193,797	1,198,746	1,202,369
September	1,198,282	1,204,083	1,204,024	1,204,139	1,201,573	1,191,842	1,198,800	1,202,420
October	1,206,307	1,211,758	1,212,467	1,211,878	1,211,386	1,199,356	1,207,107	1,210,759
November	1,217,276	1,219,235	1,222,340	1,220,335	1,217,901	1,210,935	1,215,735	1,219,417
December	1,222,380	1,224,970	1,228,546	1,225,256	1,220,996	1,215,146	1,220,756	1,224,430
Average Customers Per Month	**1,213,917**	**1,216,088**	**1,217,648**	**1,218,832**	**1,216,119**	**1,209,929**	**1,213,037**	**1,215,523**
Percent Change From Prior Year		**0.2%**	**0.1%**	**0.1%**	**-0.2%**	**-0.5%**	**-0.3%**	

Revenues, expenses, and operating income are expressed on a per-employee and per-customer basis in the table below.[84] The 2007 test year revenue, expenses, and operating income in this schedule are adjusted test year amounts from DEO's Comparative Income Statements contained in Schedule C-11.2 of its filing. According to the Company,

[79] Response to Data Requests BRCS-WF-02-003 through WF-02-005.
[80] Response to Data Request BRCS-WF-02-003, attachment *C-9.1 updates_013008.xls*, tab *C9.1A_total_pension out* which updates Schedule C-9.1.
[81] Standard Filing Requirements, Schedule C-9.1, tab C9.1A_total_pension out.
[82] Workpaper *B(2)_Follow up question WF 02-03-05.xls* provided by Dominion in a March 7, 2008 e-mail message from Vicki Friscic.
[83] Response to Data Request BRCS-WF-01-022. See Workpaper *B(2)_Operational Data Comparison.xls*, Tab *Customers*.
[84] Workpaper *B*(2)*_Operational Data Comparison.xls*, Tab *Per Customer_Employee Metrics*.

adjusted test year amounts reflect DEO's proposal to make the test year income statement accurately reflect the Company's financial condition under current rates and provide an appropriate basis for setting rates.[85] Such adjustments reflect various annualizations, reclassifications, normalizations, additions, and eliminations.[86] Actual operating income for the years 2002-2006 has averaged $118 million in total, or $97 per customer, whereas the Company projected $46 million in total income and $38 per customer for its adjusted 2007 test year. Actual operating income for 2007 was $98 million or $81 per customer. The primary difference between the adjusted test year income and actual income for 2007 is the test year adjustments.

Table 8: Per Customer and Per Employee Metrics 2002-2007[87]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Per Customer and/or Per Employee Metrics (Adjusted Test Year)
2002 through 2007

	2002	2003	2004	2005	2006	2007 Actual	2007 Adjusted Test Year	Average 2002 - 2006
Revenue	$ 809,533,111	$ 1,076,782,538	$ 1,164,287,793	$ 1,417,549,316	$ 1,257,042,742	$ 1,082,276,873	$ 1,053,896,931	$ 1,145,039,100
Expense	$ 692,247,915	$ 947,606,025	$ 1,037,468,860	$ 1,294,807,233	$ 1,161,394,354	$ 984,583,663	$ 1,007,690,270	$ 1,026,705,277
Operating Income	$ 117,285,196	$ 129,174,513	$ 126,818,933	$ 122,742,083	$ 95,648,388	$ 97,693,210	$ 46,206,661	$ 118,333,823
Average Monthly Customers	1,213,917	1,216,088	1,217,648	1,218,832	1,216,119	1,209,929	1,213,037	$ 1,216,521
Average Employees Per Month	1488	1444	1425	1415	1414	1439	1457	$ 1,437
Revenue per Customer	$ 667	$ 885	$ 956	$ 1,163	$ 1,034	$ 894	$ 869	$ 941
Revenue per Employee	$ 543,919	$ 745,953	$ 817,283	$ 1,001,743	$ 888,893	$ 752,147	$ 723,499	$ 799,558
Expense per Customer	$ 570	$ 779	$ 852	$ 1,062	$ 955	$ 814	$ 831	$ 844
Expense per Employee	$ 465,116	$ 656,468	$ 728,261	$ 915,004	$ 821,257	$ 684,253	$ 691,778	$ 717,221
Operating Income per Customer	$ 97	$ 106	$ 104	$ 101	$ 79	$ 81	$ 38	$ 97
Operating Income per Employee	$ 78,803	$ 89,487	$ 89,022	$ 86,738	$ 67,636	$ 67,894	$ 31,721	$ 82,337
Change in Income Per Customer		9.94%	-1.95%	-3.31%	-21.90%	2.66%	-52%	

The Company's use of adjusted test year amounts in its Comparative Income Statements in Schedule C-11.2 does not produce an apples-to-apples comparison to prior year results. Prior year actual results reflect the timing and synchronization differences between gas cost revenue and purchases, the inclusion of the net pension credits experienced by the Company each year, and many of the other issues addressed by the Company's proposed adjustments in Schedules C-3.1 through C-3.31. A better comparison would be prior years' actual results to unadjusted test year values as shown below.

[85] Direct Testimony of Vicki Friscic, p. 5.
[86] Direct Testimony of Vicki Friscic, pp. 5-12, and Schedules C-3 through C-3.31 in the Company's filing for detail supporting the Company's proposed adjustments to operating income.
[87] Workpaper *B(2)_Operational Data Comparison.xls*, Tab *Per Customer_Employee Metrics.*

Table 9: Prior Years' Actual Results Compared to Unadjusted Test Year Values[88]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
Per Customer and/or Per Employee Metrics (Unadjusted Test Year)
2002 through 2007

	2002	2003	2004	2005	2006	2007 Actual	2007 Unadjusted Test Year	Average 2002 - 2006
Revenue	$ 809,533,111	$ 1,076,782,538	$ 1,164,287,793	$ 1,417,549,316	$ 1,257,042,742	$ 1,082,276,873	$ 1,145,355,263	$ 1,145,039,100
Expense	$ 692,247,915	$ 947,608,025	$ 1,037,468,860	$ 1,294,807,233	$ 1,161,394,354	$ 984,583,663	$ 1,039,358,821	$ 1,026,705,277
Operating Income	$ 117,285,196	$ 129,174,513	$ 126,818,933	$ 122,742,083	$ 95,648,388	$ 97,693,210	$ 105,996,442	$ 118,333,823
Average Monthly Customers	1,213,917	1,216,088	1,217,648	1,218,832	1,216,119	1,209,929	1,213,037	$ 1,216,521
Average Employees Per Month	1488	1444	1425	1415	1414	1439	1457	$ 1,437
Revenue per Customer	$ 667	$ 885	$ 956	$ 1,163	$ 1,034	$ 894	$ 944	$ 941
Revenue per Employee	$ 543,919	$ 745,953	$ 817,283	$ 1,001,743	$ 888,893	$ 752,147	$ 788,285	$ 799,558
Expense per Customer	$ 570	$ 779	$ 852	$ 1,062	$ 955	$ 814	$ 857	$ 844
Expense per Employee	$ 465,116	$ 656,466	$ 728,261	$ 915,004	$ 821,257	$ 684,253	$ 713,519	$ 717,221
Operating Income per Customer	$ 97	$ 106	$ 104	$ 101	$ 79	$ 81	$ 87	$ 97
Operating Income per Employee	$ 78,803	$ 89,487	$ 89,022	$ 86,738	$ 67,636	$ 67,894	$ 72,766	$ 82,337
Change in Income Per Customer		9.94%	-1.95%	-3.31%	-21.90%	2.66%	11%	

Unadjusted test year operating income is $106 million versus the adjusted test year operating income of $46 million. The most notable differences between the unadjusted test year and adjusted test year operating income is DEO's proposed normalization adjustment to base year revenue ($14 million) and removal of the net pension credit ($48 million) from the test year expenses.[89] The Company's Schedule C-11.2 should reflect unadjusted test year operating income in 2007, as shown in Blue Ridge's restatement of Schedule C-11.2 below.

[88] Workpaper B*(2)_Operational Data Comparison.xls*, tab *Per Employee_Customer Metrics*.

[89] See Adjustment C-3.3 for Base Revenue adjustment and Adjustment C-3.26 for the Net Pension Credit adjustment in the Company's Standard Filing workbook *C-3 and 3.1.xls*.

Table 10: Blue Ridge Restatement of Schedule C-11.2[90]

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Comparative Income Statements (Total Company) (as revised by Blue Ridge Consulting Services)
2002 - 2006 and the Twelve Months Ending December 31, 2007

Type of Filing: Original
Work Paper Reference Nos.:

Schedule C-11.2
Page 1 of 1
Witness Responsible:
V. H. Friscic

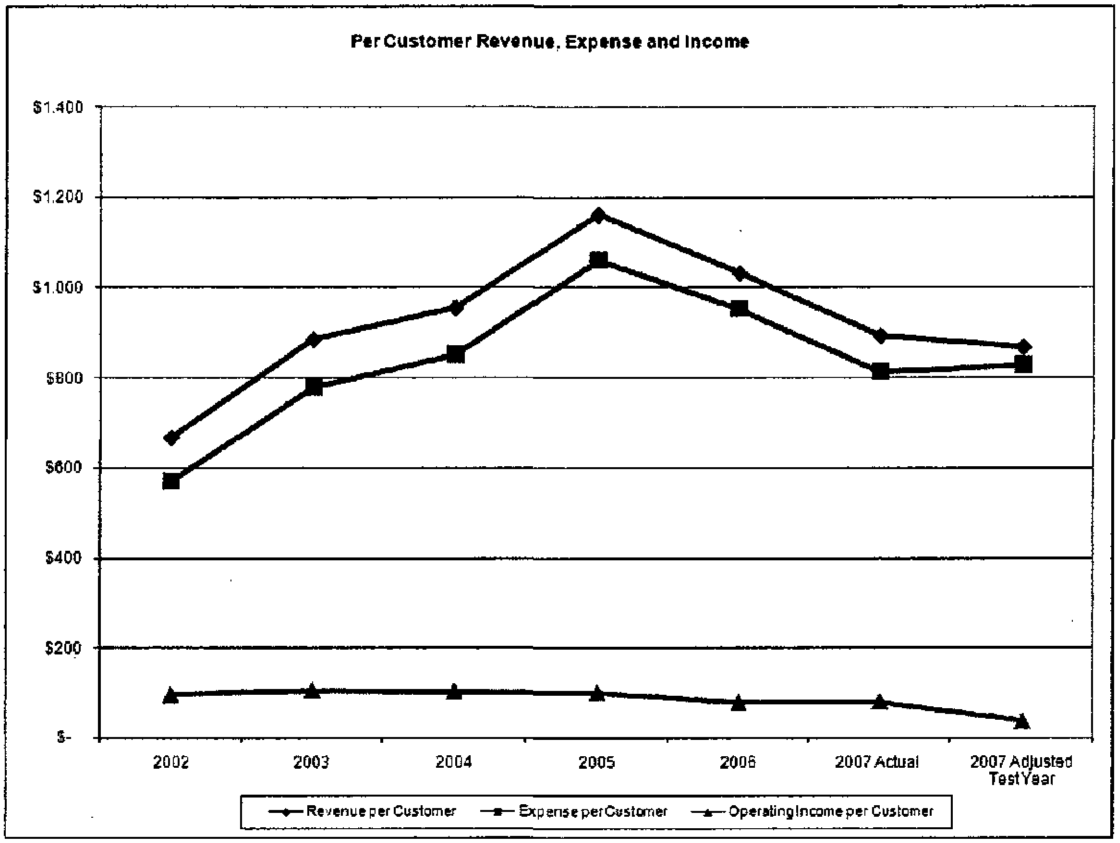
Line		Unadjusted Test Year	Most Recent Five Calendar Years				
No.	Description	2007	2006	2005	2004	2003	2002
1	Operating Revenues:						
2	Gas Sales Revenue	$ 1,106,070,232	$ 893,667,705	$ 1,117,550,634	$ 868,896,574	$ 787,354,664	$ 539,046,173
3	Other Operating Revenue	39,285,031	363,375,037	299,998,682	295,391,219	289,427,874	270,486,938
4	Total Operating Revenues	1,145,355,263	1,257,042,742	1,417,549,316	1,164,287,793	1,076,782,538	809,533,111
5	Operating Expenses:						
6	Purchase Gas (Net)	537,851,555	682,281,654	857,763,586	647,889,972	575,471,880	340,155,649
7	Other Operation & Maintenance	302,304,651	299,583,249	224,320,377	179,887,240	167,989,742	162,092,666
9	Depreciation	57,844,882	55,654,072	52,768,516	51,438,490	49,799,860	49,371,357
10	Other Taxes	104,550,956	103,699,665	115,540,835	105,631,013	96,538,187	94,536,564
11	Income Taxes	36,806,777	20,195,714	44,413,919	52,622,145	57,808,356	46,091,679
12	Total Operating Expenses	1,039,358,821	1,161,394,354	1,294,807,233	1,037,468,860	947,608,025	692,247,915
13	Net Operating Income	105,996,442	95,648,388	122,742,083	126,818,933	129,174,513	117,285,196
14	Other Income and Deductions (Net)	3,827,726	5,524,346	4,263,186	1,444,454	3,194,723	3,761,368
15	Income before Interest Charges	109,824,168	101,172,734	127,005,269	128,263,387	132,369,236	121,046,564
16	Interest Charges	34,336,677	57,398,360	38,129,652	25,883,624	26,734,187	27,524,939
17	Net Income	75,487,491	43,774,374	88,875,617	102,379,763	105,635,049	93,521,625
18	Extraordinary Items - Income (Expense)	-	-	-	-	(235,341)	-
19	Earnings Available For Common Stock	$ 75,487,491	$ 43,774,374	$ 88,875,617	$ 102,379,763	$ 105,399,708	$ 93,521,625

Findings

With the exception of 2006, both revenues and expenses have been trending upward over the past several years and the Company's operating income has remained relatively stable, averaging roughly $118 million per year or about $97 per customer. The Company's adjusted test year projections contemplate significantly reduced revenues, slight decreases in costs, and substantially lower operating income in total and on a per customer basis. Ultimately, 2007 revenues were higher than the Company anticipated while costs were lower than expected. Operating income was $97.6 million, or $81 per customer, in 2007, compared to the Company's adjusted test year assumptions of $46.2 million in total operating income and $38 per customer in its adjusted test year.

[90] Workpaper *B(2)_C-5 to 13 (adjusted by Blue Ridge).xls.*

Figure 3: Per Customer Revenues, Expense, and Income 2002-2007[91]



Conclusions and Recommendations

The Commission Staff may wish to consider regulatory adjustments to the Company's proposed test year adjustments. Given the amount by which the Company's adjusted test year operating income deviates from previous trends and its actual performance for 2007, these macro level analyses suggest that a detailed review and, potentially, other adjustments to the Company's test year, both in terms of revenues and costs, may well be warranted if Staff disagrees with the Company's rationale for the test year adjustments. Furthermore, as explained above, the Company's Schedule C-11.2 should also be revised to reflect unadjusted test year values in 2007 to provide a relevant comparison of 2007 results to actual results for the prior five years.

[91] Workpaper B(2)_*Operational Data Comparison.xls*, Tab *Per Customer_Employee Metrics*.

Operating Income Task B.3

Task B.3-The auditor selected shall work with Staff and develop an investigation audit plan directed at the significant issues of the case.

See discussion on FERC Account 923 in Rate Base Task C.16 of this report. No other significant issues were developed during the course of the audit.

Operating Income Task B.4

Task B.4-Compare the final approved budget to five actual, historical years to determine whether the test year budgeted information is representative of historical trends. Abnormalities of the budget shall be noted and investigated.

Background

Similarly to the analysis described in the section Operating Income Task B.1, Blue Ridge compared the 2007 budget revenue and expense prepared by the Company with five prior years of actual results to identify unusual trends or variances. The variance analysis in this task compares the Company's 2007 budget to actual prior revenue and expenses from the Company's SAP natural account income statements rather than its FERC account income statements. The reason that Blue Ridge used the actual prior revenue and expenses from the Company's SAP natural account income statements is that the Company prepares its budget data on a natural account basis only. The analysis prepared for the section Operating Income Task B.1 was on a FERC account basis because the Company's test year values were converted to FERC from the SAP natural account system.

In response to data requests, the Company provided the budget values for 2007[92] and the actual natural account income statements.[93] All schedules supporting the 2007 budget and 2002 – 2006 actual results were included within a single Microsoft Excel workbook. Material variances between the budget values and the average of the five prior years of actual results were submitted to the Company, which returned them with explanations.[94]

Analysis

To compare DEO's 2007 budget with prior year actual results, Blue Ridge requested the Company's revenue and expenses by natural account for the years 2002 through 2006. Blue Ridge created a summary schedule by natural account to synthesize the data from the two different sources. This summary by account organizes DEO's revenue and expenses according to (1) primary revenue or expense category, then (2) two levels of subcategories, and then (3) individual revenue and cost elements or account description.

[92] Response to Data Request BRCS-WF-01-008.
[93] Response to Data Request BRCS-WF-02-014.
[94] Response to Data Request BRCS-WF-06-002 and Workpaper *B(4)_WF 06-02 Variance between Budget Year 2007 and 5 Years Actual.xls.*

GL Acct	Category	Sub-Category	Sub-Category	Rev/Cost Elements

Budget 2007 amounts were then compared with the average of the five prior years at the individual account level. Blue Ridge identified specific accounts with variances representing an increase or decrease of greater than $1,000,000 and 20% over the 5-year average of historical results.

							MATERIALITY THRESHOLDS	
							1,000,000	20%
							BUDGET GREATER (LESS) THAN ACTUAL	
GL Acct	Category	Sub-Category	Sub-Category	Rev/Cost Elements	2007 Budget	Actual Results 5-Year Average	AMOUNT	%

Using account level data to identify material variances resulted in variances attributable to budget values being recorded in different accounts from historical book results. Consequently, Blue Ridge created a higher level summary worksheet as an alternative which summarizes revenue and expenses at the subcategory level noted above. The auditors then asked DEO to explain the material variances identified at the subcategory level. If the subcategory level of granularity was not sufficient to explain the variance adequately, the Company was asked to go down to the account level to explain the variance.[95]

Findings

Comparison of the 2007 budget to the average of the five prior years of actual resulted in the following. Thirteen of the 28 subcategories reflected variances exceeding $1,000,000 and 20% over the average of the period 2002-2006. Total 2007 budget revenue is greater than the 5-year historical average by $53 million. This is primarily due to the migration of retail customers to the Energy Choice program where their natural gas commodity service is purchased from third party suppliers which increases transport revenues. This increase is offset by a reduction in retail sales ($26 million) and non-regulated revenue ($18 million) due to inclusion of a Sale of Storage in the 5-year average in conjunction with the Standard Service Offer commodity service restriction undertaken by the Company.[96]

Budget 2007 operations and maintenance expenses are $74 million greater than the 5-year historical average due to the following: an increase in bad debt expense of $89 million over the 5-year historical average caused by an increase in PIPP rider rate in 2006, an increase in outside service costs of $12 million for contractors performing work on pipeline integrity, leak repairs and damage prevention as well as increases in legal

[95] Data request BRCS-WF-06-002.

[96] Workpaper *B(4)_WF 06-02 Variance between Budget Year 2007 and 5 Years Actual.xls*, tab Summary by Category.

service expense, and an increase of $11 million in shared service costs from DRS.[97] These increases are offset somewhat by a decrease in purchased gas costs due to the migration of sales customers to the Energy Choice program.[98]

Conclusions and Recommendations

DEO's 2007 budget appears to be generally representative of historical trends. As noted in Blue Ridge's analysis under section Operating Income Task B.1, the Company was asked to explain why shared service cost allocations increased in 2007 in follow-up data requests to the Company's response to BRCS WF-04-01 and BRCS DWS-05-05. This issue is discussed in more detail in section Rate Base Task C.16.

Operating Income Task B.5, B.6, and B.7

Tasks B.5, B.6 and B.7 – Document the budget process. Interview Company personnel responsible for the compilation of the budgeted information. Interview a select sample of company personnel (function heads) that had input into the budget and track their input through the budget process.

Background

To complete the analysis for Operating Income Tasks B.5, B.6, and B.7, Blue Ridge reviewed the information provided with the Company's filing, interviewed no fewer than 10 key personnel involved in the budget formulation and approval process, issued more than 30 data requests related to the Company's budget process, and reviewed the information provided by the Company in response. The auditors also reviewed the various budget timelines and flowcharts prepared by the Company in response to discovery to document its budget process. Blue Ridge found that the DEO budget process is driven by executive management's goals for operating earnings per share, free cash flow, return on invested capital (ROIC), credit metrics, dividends, and operational metrics.[99] Each business segment is provided with financial targets to ensure the objectives are achieved.[100] The business segments then finalize their detailed budgets between July and November consistent with corporate-level objectives.[101] The Financial and Business Services group serves as the liaison between executive management and business segment management by performing the following tasks:

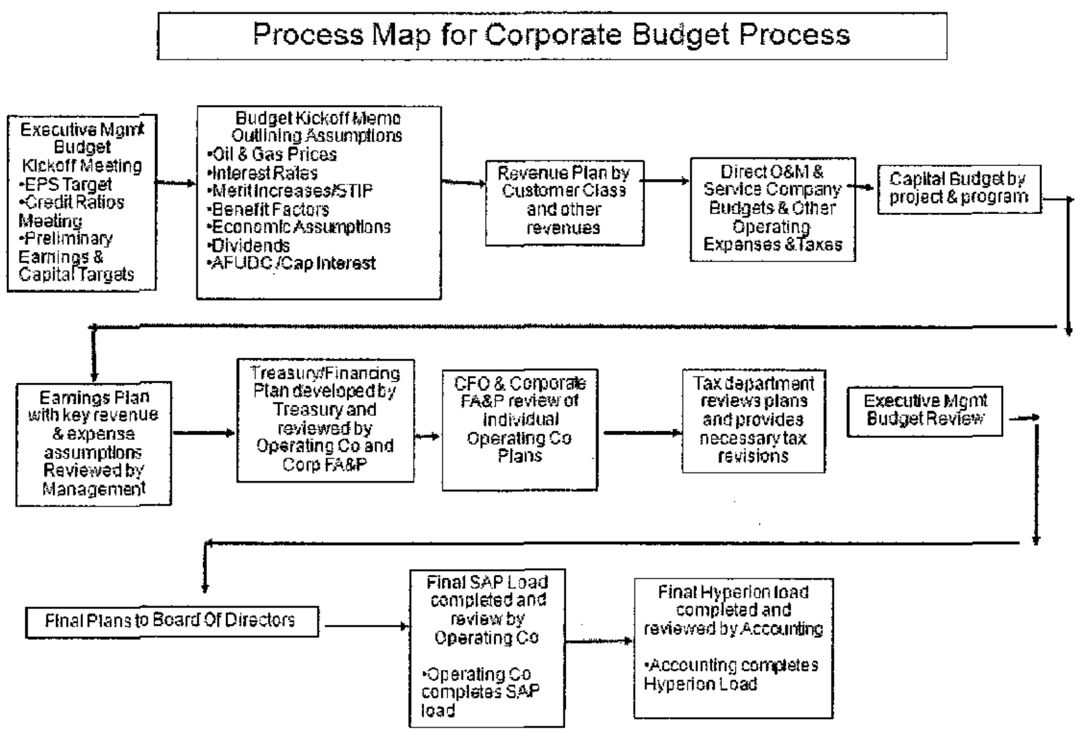
[97] Workpaper *B(4)_WF 06-02 Variance between Budget Year 2007 and 5 Years Actual.xls*, tab Summary by Category.
[98] Workpaper *B(4)_WF 06-02 Variance between Budget Year 2007 and 5 Years Actual.xls*, tab Summary by Category.
[99] Response to Data Request BRCS-GPR-01-003 - Dominion East Ohio Rate Case Survey: Functional Area – Budgeting and Forecasting.
[100] Response to Data Request BRCS-GPR-01-003 - Dominion East Ohio Rate Case Survey: Functional Area – Budgeting and Forecasting.
[101] Response to Data Request BRCS-GPR-01-003 - Dominion East Ohio Rate Case Survey: Functional Area – Budgeting and Forecasting.

1. Providing financial and operational targets
2. Developing the Five-year Financial Plan/Budget
3. Establishing the O&M budgeting targets and timelines necessary to meet Corporate's five-year financial plan due dates
4. Establishing capital budget targets and timelines
5. Preparing actual vs. budget variance analyses
6. Preparing budget updates using actual results plus remaining months' budget[102]

The annual budget and the Five-year Plan are created simultaneously; the Five-year Plan is re-evaluated each year.[103] The revenue in the Five-year Plan is developed based on a fresh-look approach, meaning that the budget is reviewed anew each year. Review meetings are held with directors to agree on what is included in the Five-year Plan.

The following flowchart prepared by Dominion Resources, Inc. (DRI) summarizes the Corporate Budget Process:[104]

Figure 4: Corporate Budget Process Flowchart

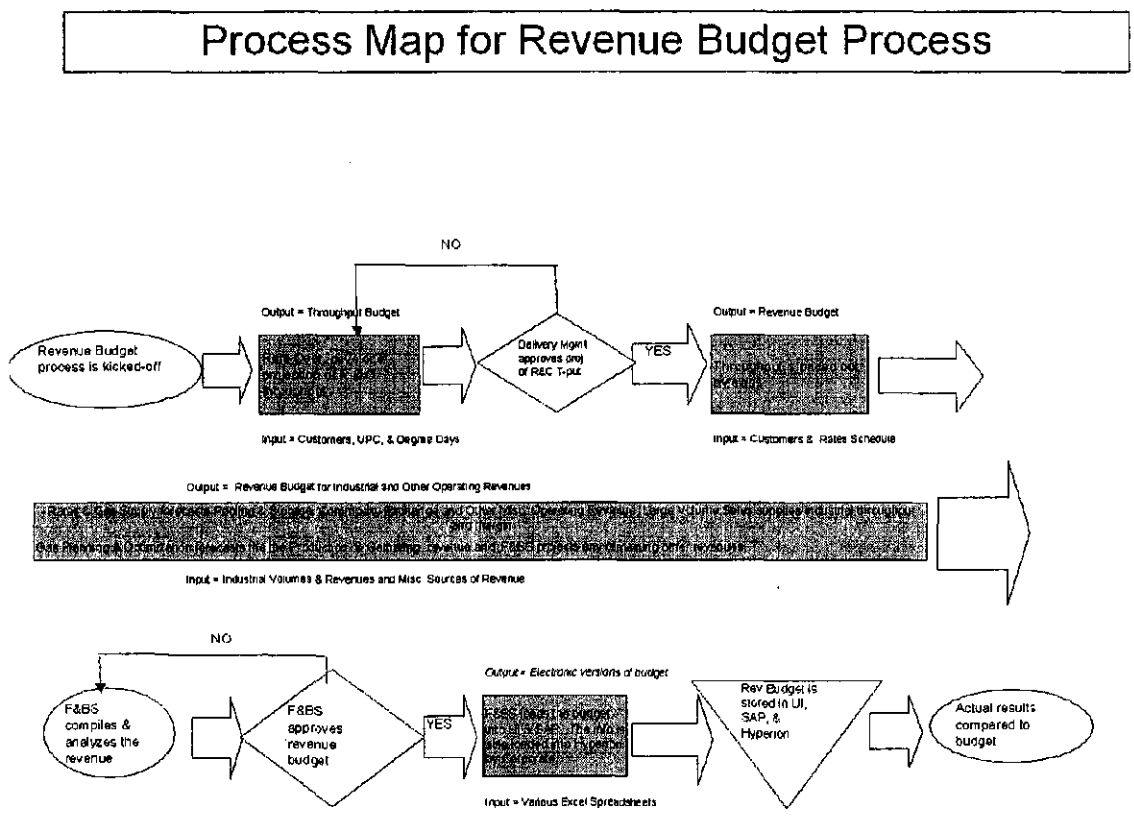


[102] Response to Data Request BRCS-GPR-01-003 - Dominion East Ohio Rate Case Survey: Functional Area – Budgeting and Forecasting.
[103] Corbin & Laley - Interview on 071219.
[104] Response to Data Request BRCS-WF-01-005.

Analysis

Blue Ridge interviewed DEO's President,[105] Vice President of Operations,[106] the Dominion Resources, Inc. (DRI) Manager – Financial and Business Services, and the Senior Financial Analyst that reports to her to obtain a detailed description of the DEO budget process.[107] Delivery targets for earnings and capital are set for each business unit by executive management. High level assumptions regarding energy prices, interest rates, wage increases, benefit factors, etc. are then developed. Forecasted revenue by customer class is developed first starting with a volume forecast in late July and then a completed revenue forecast in mid-August. Development of the load forecast used to produce the revenue budget is discussed in detail under section Operating Income Tasks B.11 and B.12 below. The following flowchart summarizes the revenue budget process.[108]

Figure 5: Revenue Budget Process Flowchart



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105 Klink – Interview on 071218.

106 Searles – Interview on 071219.

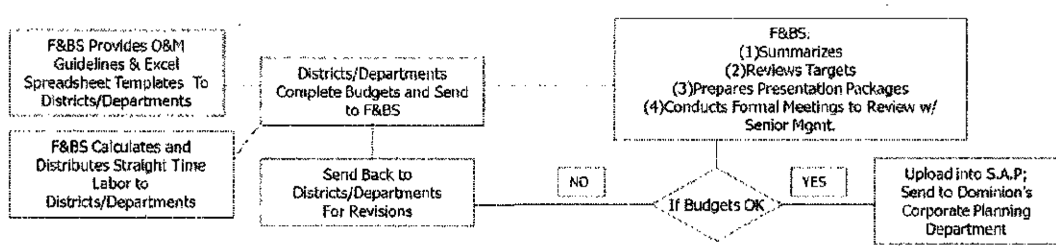
107 Corbin & Laley - Interview on 071219.

108 Response to Data Request BRCS-WF-01-005.

O&M budget planning begins early in the year and is completed by September. The Company establishes an O&M target as a starting point. During her interview, the Manager – Financial and Business Services explained that the O&M budget is developed along two "tracks"—high level and detailed level. The high level is the target starting point described above, which for 2008, for example, would be equal to the 2007 budget + 3%. The detailed level builds the budgets for each department from the bottom up. As part of this bottom-up approach, corporate provides benefit increases, the Financial and Business Services group create the labor budget, and field personnel perform non-labor budget calculations. The budgeting for labor and capital is zero-based. The O&M budget process is summarized in the flowchart below.[109]

Figure 6: O&M Budget Flowchart

Process Map for the O&M Budget



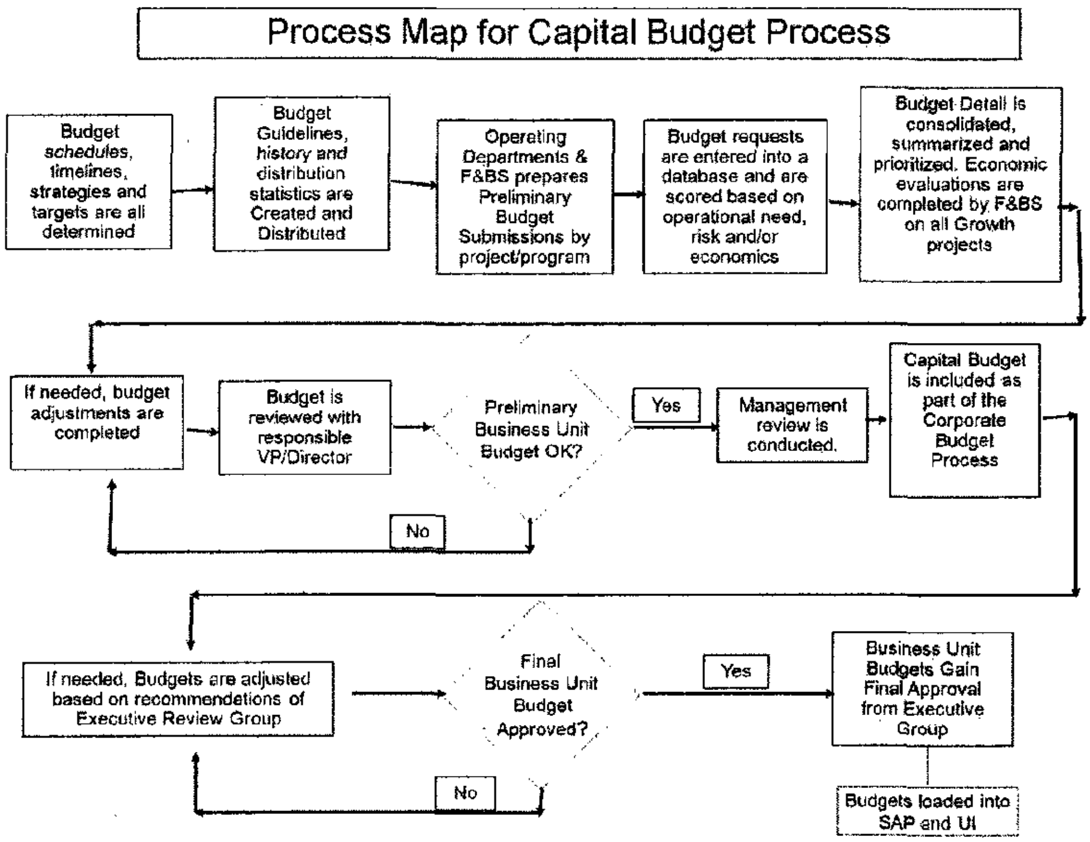
- F&BS provides O&M Budget Guidelines to District/Department budget personnel that includes:
  - Employee Listing
  - Due Dates
  - Targets
  - Budget Templates in Excel Spreadsheets
  - Benefit Rates, Payroll Tax Rates, Incentive Rates
  - Budget History
  - Instructions/Miscellaneous Notes
- All Straight Time Labor is calculated by F&BS and distributed to the Districts/Departments.
- Financial Analysts/Operating Budget Analysts build annual budgets by the following categories:
  - Month
  - Department/Operating Shop Location
  - GL Account, e.g., 5300110 is representative of Salaried Labor/Straight Time and 5303030 is representative of Contractor Services.
- O&M budgets are submitted to F&BS and summarized. Targets are reviewed/established. Presentation packages are developed for Formal Review Sessions where budgets are reviewed with Senior Mgmt. Revisions, if needed, are requested from the Districts/Departments.
- After all revisions are completed and targets are met, budgets are loaded into S.A.P. and provided to Dominion's Corporate Planning Department.

The review process for the O&M and capital budgets begins with the DEO V.P. of Gas Operations. Next, Dominion Energy senior management (DEO President and the Dominion Energy CEO) approves them before they are consolidated with the various other budgets from the other companies comprising the Energy Group. Finally, the Chief Financial Officer signs off the consolidated budget.

[109] Response to Data Request BRCS-WF-01-005.

The capital process starts in the April to May timeframe. Projects of $100,000+ are identified individually. The capital budget is developed according to the asset management model. During September several budget review meetings are held, and by the month's end, DEO and Dominion Energy have their first look at the financial plan. The capital budget process is summarized in the flowchart below.[110]

Figure 7: Capital Budget Process Flowchart



The following factors filter into the budget: overall delivery targets and the 5-year plan for business units, earnings and capital targets for each business unit (e.g., Energy), targets at a more granular level (e.g., DEO), macro assumptions for consistency in the 5-year plan, usage, revenues prices, input from taxes, and approved volumes. The financial planning tool used in this process is Utilities International (UI).

October 1st is the first submission of the budget. Between October and December, the budget plan is revised when necessary based on updated information on service company costs, benefits, etc. The budget is then delivered to corporate for review and feedback. The Company's goal is to have the budget to the Board of Directors by mid-December.

110 Response to Data Request BRCS-WF-01-005.

The Board of Directors uses the budget to provide earnings guidance to investors and analysts.

The budget variance process was described by DRI's Senior Management and the Financial and Business Services Financial Analyst during her interview.[111] The process is summarized as follows: monthly close occurs on the first day following month-end; financial results are received by Financial and Business Services personnel supporting DEO; variances from the plan are analyzed; and explanations for the variances are developed. A variance meeting with the Accounting group is held on the third day after month-end closing. By the seventh or eighth day of the month, reports are sent to Richmond, Virginia. The accounting monthly close is performed at a higher level than an account basis. The variance analysis is focused at a high level of revenue and O&M expenses as a whole, but variances are investigated at a more granular level to determine their sources if necessary. Budget to actual variance reports are run from SAP, which assimilates information from all business units.

Mid month operations review meetings are held to discuss O&M, metrics, etc. with the DEO President, the DEO VP of Gas Operations, and the DEO Director of Rates and Gas Supply. The results of any variances discussed in the third-day meetings are addressed in the monthly operations meetings.

Findings

The Company's budget process and SAP system does not currently permit development of budgets on a FERC account basis. As noted in Operating Income Tasks B.1 and B.4, DEO budgets are developed in the SAP natural account format only. This makes actual vs. budget variance analyses difficult in a regulatory case filing that relies predominantly on FERC-based accounting. Additional analyses and discussions with Company personnel were required to bridge the gap between the various schedules prepared for the Company's rate case filing and certain underlying source data that are available only in the SAP natural account format.

Based on Blue Ridge's discussions with senior management and the Manager of Financial and Business Services, no budget resets occurred in 2007.[112] They explained that budget resets occur only if something significant happens in the business. Overall financial budgets and O&M/capital budgets are not changed, but the Company may redistribute funds to cover an emerging issue or a variance may be approved.

Actual versus budget comparisons were not performed at the DEO level prior to October 1, 2007. They were performed at the total distribution company level. Currently, they are performed monthly at the DEO level as well. The Director of Accounting explained that the Company did maintain budget to actual analysis at the entity level (as opposed to

[111] Laley - Inteview on 071218 MJM.
[112] Corbin & Laley - Interview on 071219.

business segment level) prior to the October 1, 2007 corporate reorganization.[113] He referred to these as "income reasonability reviews." He explained that the details in these income reasonability reviews did not usually get reviewed by upper management.

When asked about changes that have occurred in the budget process since the last rate case, the Manager of Financial and Business Services stated that several incremental changes have been implemented related to the budget process. Relatively recent changes include a change to an asset management process, which scores capital projects, as well as centralization of the budgeting of labor.[114]

Conclusions and Recommendations

Blue Ridge's assessment of the Company's budget process is that it is sound and can reasonably be relied upon to produce accurate budgeted operating expenses and capital additions. Corporate executive management and business segment senior management are integrally involved in the development of the original budget and Five-year Plan as well as recurring operations meetings to understand the causes of variances from the plan. However, we noted that there is no formal approval by senior management of the load forecast based upon defined standards before it is distributed to other departments. This and other issues associated with the Company's load forecast process are discussed in detail in Operating Income Tasks B.11 and B.12.

Operating Income Task B.8

Task B.8-As actual information for the budgeted months become available, compare and analyze budgeted months to actual months. Significant variances shall be investigated.

Background

This analysis compares DEO's unadjusted test year, which is comprised of three months of actual results and nine months of budget, to 2007 projected results based on the most current actual results available. Blue Ridge issued a standing data request for the Company to provide updates to actual results for the year 2007 as they became available.[115] Because of the timing of the audit fieldwork, the Company was able to provide us a full year of actual results for 2007 which is an optimal benchmark for comparing the Company's 2007 budget and identifying anomalies.

Unadjusted test year values for 2007 were compiled from DEO's workpaper WPC 2.1 from its Standard Filing Requirements while actual 2007 results were obtained from DEO's income statements by FERC account. As noted above in the section Operating Income Task B.1, the Company's budget data is typically prepared in natural account form only. However, DEO's 2007 budget for the months of April through December

[113] Sciullo & Worcester - Interview on 080107.
[114] Corbin & Laley - Interview on 071219.
[115] Data Request BRCS-WF-01-011.

2007 had to be converted to FERC accounts to prepare its test year revenue and expenses.[116] Consequently, the comparison of the 2007 unadjusted test year to 2007 actual results was performed using FERC-based income statements. All schedules supporting the 2007 test year and 2007 actual results were included within a single Microsoft Excel workbook. Material variances between the test year values and 2007 actual results were submitted to the Company, which returned them with explanations.[117]

Analysis

DEO provided its 2007 FERC income statement with 12 months of actual results.[118] Blue Ridge identified specific accounts with variances representing an increase or decrease of greater than $1,000,000 and 20% over the 5-year average of historical results.

Using account level data to identify material variances resulted in some cases in variances attributable to test year values being recorded in different accounts from historical book results. Consequently, Blue Ridge created a higher level summary worksheet as an alternative which summarizes revenue and expenses at the category level. The auditors then asked DEO to explain the material variances identified at the category level. If this level of granularity was not sufficient to explain the variance adequately, the Company was asked to go down to the account level to explain the variance.[119]

Findings

Based on the comparison review, Blue Ridge noted significant variances in three of the 19 revenue and expense categories.[120] Two of the variances were in Operations Expenses while the third was in income taxes. Actual gas production and underground storage expenses were greater than the unadjusted test year by $23 million due to the removal of compressor station fuel costs and gas losses from the test year since they are recovered separately through the Transportation Migration Rider – Part B rate.

Unadjusted test year revenue is $63 million greater than 2007 actual results. Operating expenses are also greater than 2007 actual results by $55 million. The revenue and expense variances appear to be primarily due to sales that were less than planned, which results in gas cost reductions offsetting the drop in retail sales. Test year O&M expenses excluding gas costs were actually less than 2007 actual results due to recovery of gas loss costs through the Transportation Migration Rider – Part B rate as noted above ($17 million increase) and higher than expected bad debt expense ($11 million increase).[121]

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[116] Response to Data Request BRCS-DWS-01-014.

[117] Response to Data Request BRCS-WF-07-001 and Workpaper *B(8)_WF 07-01 Variance between 2007 Test Year and 2007 Actual.xls*.

[118] Response to Data Request BRCS-WF-02-014.

[119] Data request BRCS-WF-06-001(a).

[120] Workpaper *B(8)_WF 07-01 Variance between 2007 Test Year and 2007 Actual.xls* tab *Summary*.

[121] Workpaper *B(8)_WF 07-01 Variance between 2007 Test Year and 2007 Actual.xls*, tab *Summary by Account*.

The net effect of these variances is test year operating income that is $8 million or 7.7% greater than 2007 actual results.

Conclusions and Recommendations

DEO's 2007 O&M budgeting process appears to be reasonably accurate based upon the comparison to the Company's actual results for 2007. However, the Company's load forecast may have been somewhat optimistic given that retail revenue was $75 million or 10.7% less than the test year forecast. Overall, the Company's 2007 actual results appear to support the unadjusted test year operating income relied upon by the Company in its filing.

Operating Income Task B.9

Task C.9-Compare most recent prior year budget to actual results and note significant variances.

Background

Blue Ridge compared the Company's 2006 actual results with its 2006 budget to ascertain how accurate the Company's budget process was in determining its projected costs for a recent year prior to the test year. Initial data requests were issued to obtain the schedules containing 2006 budget and actual results. Material variances between the 2006 budget and actual results were submitted to the Company, which returned them with explanations.[122]

Analysis

DEO provided its 2006 budget using the SAP natural account structure.[123] This budget was compared to DEO's actual 2006 results.[124] Blue Ridge identified specific accounts with variances representing an increase or decrease of greater than $1,000,000 and 20% over the 5-year average of historical results.

Similarly to Blue Ridge's analyses in Operating Income Tasks B.1, B.4 and B.8, Blue Ridge created a higher level worksheet which summarizes revenue and expenses at the category level. The auditors then asked the Company to explain the material variances identified at the category level. If this level of granularity was not sufficient to explain the variance adequately, the Company was asked to go down to the account level to explain the variance.[125]

Findings

Blue Ridge found 15 material variances out of 28 categories of revenue and expense in the comparison of 2006 budget to 2006 actual results. Actual operating income was $294

[122] Response to Data Request BRCS-WF-06-003 and Workbook *B(9)_WF 06-03 Variance between 2006 Budget vs 2006 Actual.xls*.
[123] Response to Data Request BRCS-WF-01-008.
[124] Response to Data Request BRCS-WF-02-014.
[125] Data request BRCS-WF-06-03.

million or 26% less than the 2006 budget. According to the Company, retail sales were down $500 million or 64% primarily due to the migration of sales customers to the Energy Choice program in which they purchase natural gas commodity service from third party suppliers.[126] The migration was not anticipated in the 2006 budget. The majority of the migration in 2006 occurred when the Northeast Ohio Public Energy Council (NOPEC) established a new aggregation program through which it enrolled approximately 180,000 customers in May and June 2006.[127] This was offset somewhat by an increase in transportation revenue for the same reason. Purchased gas costs were also less than budgeted by $343 million or $48% due to the migration as well.[128] On the O&M side, uncollectible expense was greater than planned by $59 million due to an increase in the PIPP rider rate during 2006 that was not reflected in the budget. DEO filed its application to increase the PIPP rate in November 2005 and revised its application in December 2005. The rate of $0.5653 per Mcf was both approved and implemented by the Commission in February 2006. DEO's 2006 plan was established before the Company filed its application and received approval for the new rate.[129]

Conclusions and Recommendations

The significant variances between the 2006 budget and actual results are the result of events that occurred after the budget was approved for 2006. The most significant event was the migration of customers to the Energy Choice program that occurred in mid-2006 – an event not anticipated in the budget. In contrast, DEO's 2007 actual results did not contain these unanticipated changes that significantly increase or decrease operating income from the approved budget. Since DEO was able to provide a full year of actual results for the comparison of the 2007 test year to actual in Operating Income Task B.8, Blue Ridge recommends that the Commission focus on the comparison in Task B.8 as a benchmark of the reliability of the budget process instead of the comparison of the 2006 budget to 2006 actual results.

Operating Income Task B.10

Task C.10 – Prepare and analyze monthly test year and three historical years of monthly historical consumption data (sales) and customer count by tariff.

Background

This section of the audit focuses on trends in consumption and customer data. Changes in consumption patterns and/or customer counts may help to explain observed deviations in capital expenditures, recurring expenses, and revenue data. Therefore, consumption

[126] Workpaper B(9) *WF 06-03 Variance between 2006 Budget vs 2006 Actual.xls*, tab Summary by Category.

[127] Workpaper B(9) *WF 06-03 Variance between 2006 Budget vs 2006 Actual.xls*, tab Summary by Category.

[128] Workpaper B(9) *WF 06-03 Variance between 2006 Budget vs 2006 Actual.xls*, tab Summary by Category.

[129] Workpaper B(9) *WF 06-03 Variance between 2006 Budget vs 2006 Actual.xls*, tab Summary by Category.

and customer data must be obtained and understood such that revenue and expense data contained throughout the Company's revenue requirements model may be put into proper context.

Blue Ridge requested consumption and customer data through multiple data requests and created a spreadsheet comparing monthly consumption and customer count data for the test year and five prior years.

Analysis

Blue Ridge requested the test year and five prior years' historical monthly consumption and customer data through data requests.[130] The Company's responses included actual Mcf data by month and customer group/rate schedule. The table below comprises total sales in Mcf by rate schedule[131] for the test year (2007) and the five preceding years. Blue Ridge's workpapers contain these same data disaggregated by month from January 2002 through August 2007.

Table 11: Mcf Volume by Rate Schedule 2002-2007[132]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
MCF by Rate Schedule (as measured)
2002 through 2007

	2002	2003	2004	2005	2006	2007 Actual *	2007 Test	AVG Non Test Year
GSS	81,191,436	84,402,577	77,215,551	84,240,427	57,621,274	49,384,169	49,141,601	76,934,263
LVGSS	2,880,987	3,147,736	2,260,261	2,216,450	1,654,275	1,523,709	1,821,342	2,431,942
ECTS	78,474,181	87,157,887	81,478,610	76,759,583	77,675,323	96,421,985	94,167,209	80,309,073
LVECTS	2,948,659	4,258,513	5,249,720	6,155,612	6,304,267	7,297,812	7,173,298	4,983,354
TSS	1,034,846	891,145	898,608	813,173	1,035,978	1,109,142	1,116,465	934,750
GTS	38,984,133	36,963,812	28,713,918	26,058,768	32,257,104	31,909,249	31,224,390	32,595,511
DTS	12,691,552	11,189,613	12,153,121	11,792,863	10,904,798	10,940,261	12,823,612	11,746,370
Discounted	48,564,925	44,052,846	57,877,460	63,668,686	55,948,845	53,420,578	50,815,445	54,022,552
Total On System	266,770,719	272,063,609	265,847,247	271,706,583	243,401,862	252,006,605	248,283,362	263,957,804
Off System	8,207,669	9,992,458	9,540,110	6,501,004	8,608,274	8,892,609	6,341,061	8,569,903
Total System	274,978,388	282,056,067	275,387,357	278,206,686	252,010,137	260,899,213	254,624,423	272,527,707

2007 "Actual" includes one month projected (December 2007)

Customer counts by month and year are summarized in Figure 8 and Table 12 below. These data show that the Company's overall customer counts have remained stable throughout the 2002-2007 time period, albeit with a seasonal component.

[130] Data Requests BRCS-WF-01-16, BRCS-WF-01-17, BRCS-WF-01-22, BRCS-WF-02-07, and BRCS-WF-02-08.

[131] The rate schedule acronyms used in these tables are defined as follows: General Sales Service (GSS), Large Volume General Sales Service (LVGSS), Energy Choice Transportation Service (ECTS), Large Volume Energy Choice Transportation Service (LVECTS), Transportation Service for Schools (TSS), General Transportation Service (GTS), and Daily Transportation Service (DTS).

[132] Workpaper *B(10)_MCF and Customers.xls* tab *Detailed MCF Data 2002-2007.*

Figure 8: General Service Customers 2002-2007[133]

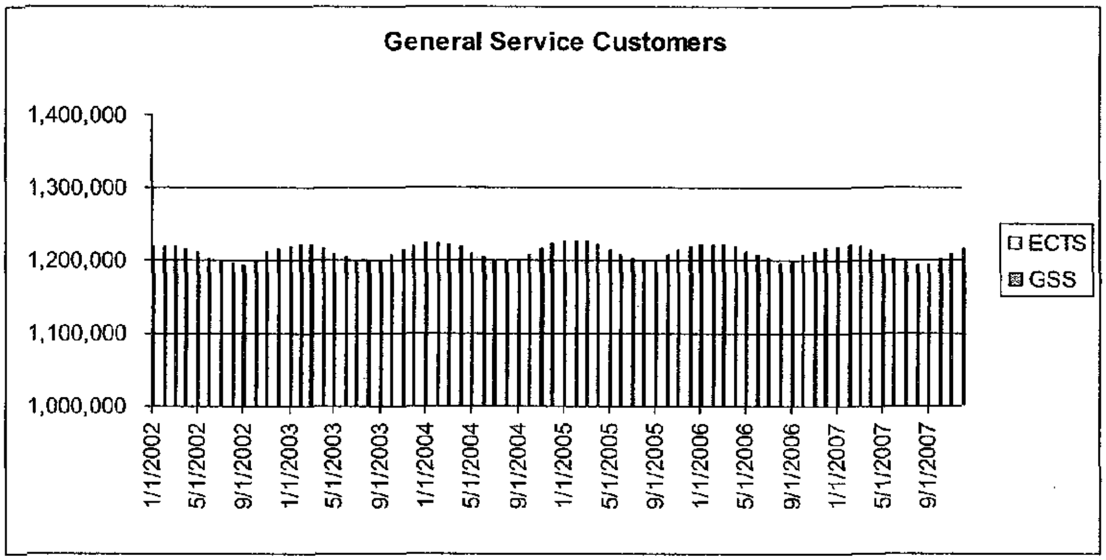


Table 12: Non Storage Customers by Month 2002-2007[134]

Case No. 07-0829-GA-AIR
Non Storage Customers by Month
2002 through 2007

	2002	2003	2004	2005	2006	2007 (Actual)	2007 (Test)	Average Non Test Year
January	1,223,707	1,225,290	1,228,727	1,231,195	1,226,147	1,223,868	1,223,760	1,227,013
February	1,224,592	1,226,942	1,229,270	1,232,053	1,227,319	1,225,652	1,225,543	1,228,035
March	1,224,346	1,225,401	1,227,664	1,231,312	1,226,363	1,223,763	1,223,639	1,227,017
April	1,222,260	1,221,177	1,223,419	1,226,487	1,223,626	1,220,013	1,219,903	1,223,394
May	1,216,858	1,215,442	1,215,532	1,219,920	1,217,388	1,211,130	1,213,365	1,217,028
June	1,208,075	1,210,830	1,209,431	1,212,089	1,212,214	1,205,641	1,206,881	1,210,528
July	1,203,219	1,205,587	1,206,025	1,207,335	1,207,033	1,198,001	1,202,213	1,205,840
August	1,199,698	1,202,342	1,204,336	1,203,985	1,201,482	1,193,797	1,198,746	1,202,369
September	1,198,282	1,204,083	1,204,024	1,204,139	1,201,573	1,191,842	1,198,800	1,202,420
October	1,206,307	1,211,758	1,212,467	1,211,878	1,211,386	1,199,356	1,207,107	1,210,759
November	1,217,276	1,219,235	1,222,340	1,220,335	1,217,901	1,210,935	1,215,735	1,219,417
December	1,222,380	1,224,970	1,228,546	1,225,256	1,220,996	1,215,146	1,220,756	1,224,430
Average Customers Per Month (Jan - Dec)	**1,213,917**	**1,216,088**	**1,217,648**	**1,218,832**	**1,216,119**	**1,209,929**	**1,213,037**	**1,216,521**
Percent Change From Prior Year		**0.2%**	**0.1%**	**0.1%**	**-0.2%**	**-0.5%**	**-0.3%**	

Findings

Overall, customer counts and system-wide usage have been relatively stable year over year, with the exception of 2006, which was roughly 10% warmer than the four previous

[133] Workpaper *B(10)_MCF and Customers.xls* tabs *Customers by Month, Detailed CustomerData 2002-2007* and *HSHSHS Det Cus Data 2002-2007.*

[134] Workpaper *B(10)_MCF and Customers.xls* tabs *Customers by Month, Detailed CustomerData 2002-2007* and *HSHSHS Det Cus Data 2002-2007*

years. The test year data reflect consumption that is considerably lower than the average of the period 2002 through 2006 (252,010,137 versus 272,527,707).

As depicted in Table13 as well as Figure 9 below, average monthly Mcf consumption per customer has been relatively stable (declining slightly) over the past several years.[135] The Company's test year reflects 17.54 Mcf per customer per month, while the average from 2002 through 2006 was 18.67 Mcf. With 11 months actual and one month projected (December 2007), it would appear that actual usage for 2007 will be approximately 17.92 Mcf per customer for 2007, which is lower than the average of the past five years but higher than the test year. Mcf per Heating Degree Day (HDD) charts included within Workpaper *B(10)_MCFs and Customers 2002-2007.xls* confirm these trends.

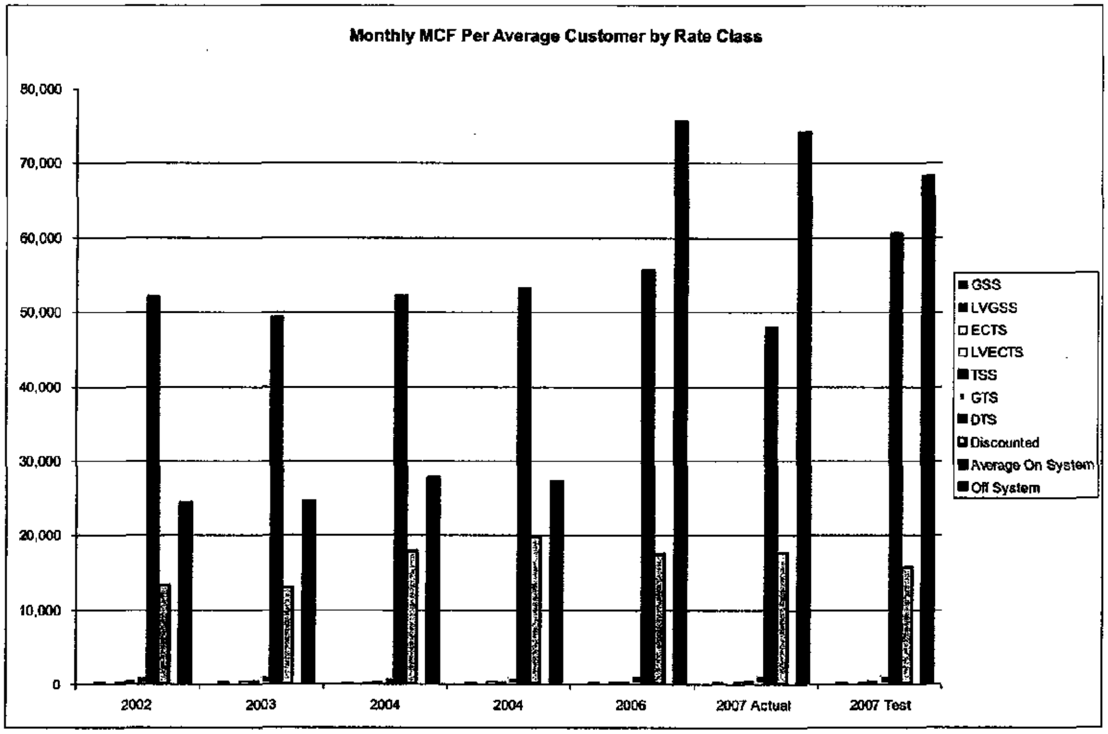
Table 13: Mcf per Average Monthly Customer 2002-2007[136]

The East Ohio Gas Company d/b/a Dominion East Ohio
Case No. 07-0829-GA-AIR
MCF Per Average Monthly Customer Count (by Rate Class)
2002 through 2007

	2002	2003	2004	2004	2006	2007 Actual	2007 Test
GSS	11	12	10	11	10	10	10
LVGSS	323	363	285	295	277	265	344
ECTS	11	12	11	11	9	10	10
LVECTS	314	368	355	374	331	344	358
TSS	255	281	186	162	202	219	221
GTS	959	1,096	881	817	1,129	1,165	1,181
DTS	52,015	49,293	52,159	53,121	55,637	47,984	60,489
Discounted	13,237	12,976	17,803	19,712	17,446	17,526	15,645
Average On System	18	19	18	19	17	17	17
Off System	24,428	24,491	27,733	27,201	75,511	74,105	68,183
Total System	18.88	19.33	18.85	19.02	17.27	17.92	17.54

[135] The notable exception is 2006 but HDD data suggest that was a relatively warm year. Indeed, 2006 has 5,554 HDD compared to an average of 6,069 over the period 2002 through 2005. Workpaper *B(10)_MCFs and Customers 2002-2007.xls.*
[136] Workpaper *B(10)_MCFs and Customers 2002-2007.xls.*

Figure 9: Average Monthly Mcf per Customer 2002-2007[137]



Conclusions and Recommendations

These data do not indicate the existence of any extreme anomalies. However, the Staff may want to consider whether an adjustment to the Company's projected volumes and associated costs and revenues is reasonable.

Operating Income Task B.11 and B.12

Tasks B.11 and B.12 - Review the Applicant's written summary explaining the forecasting (sales) methodology as it relates to the test year. (SFR Supplemental C-12) Interview Applicant's personnel responsible for the sales forecast.

Background

A utility load forecast forms the underlying foundation for a wide range of planning tasks. The commodity portion of the forecast supports the utility's commodity sourcing and/or production functions. The peak forecast supports the utility's transportation and transmission planning and may provide planning information for system operations. The forecast also provides the number of customers by class and can provide, at a high level, information for the capital budgeting process at the transmission and distribution level. The combination of number of customers, commodity sales, and peak forecast provides the basis for the utility's expected revenue stream.

[137] Workpaper *B(10)_MCFs and Customers 2002-2007.xls.*

All utility forecasting models assume "normal" weather and the output sales and peak forecast is for normal weather conditions. Many utilities used a thirty-year weather period to develop "normal" weather. Recent weather trends have demonstrated that the thirty-year time horizon may be too long and many utilities have shifted to a ten-year time horizon. Before the shift is made, the utility should analyze weather trends and compare them to present practices. Weather data is usually derived from the National Weather Service and its local stations within or nearby the utility's service territory. High and low daily temperatures are used for most forecasts and humidity and wind data may supplement that as appropriate.

Utility load forecasts are generally driven by economic models of the national economy, which are usually purchased on a subscription basis from an economic forecasting firm. The national model is then broken down into a relevant area such as a state, Consolidated Metropolitan Statistical Area or a number of selected counties to create an input data set for the utility forecasting model. The required inputs are determined by the utility's forecasting model(s).

Utility forecasting models are often a combination of three types of sub models: (1) regression model, (2) end use model, and (3) surveys. A regression model uses statistical techniques to determine the data inputs that provide the best forecast of past, actual consumption. Typical inputs may include number of dwelling units, housing starts, economic data such as household income, appliance saturations, costs of alternate or competitive fuels, building construction, commercial and industrial activity, past consumption, and weather. An end use model uses estimates of end use appliances and energy consuming equipment to forecast commodity consumption. Typical inputs for an end use model may include appliance saturations, industrial information, and building area. Less commonly, the forecast may be derived from past consumption history along with economic factors and other inputs. Some utilities with specific large customers use periodic surveys or other data gathering methods to determine the expected consumption of large commercial or industrial customers that may be planning additions or closures that are not accurately detailed using economic data.

Utility forecasting is validated by "backcasting," which is the process of applying real economic data from past periods and determining how accurately the model "predicts" sales that have actually occurred.

Blue Ridge reviewed DEO's summary explaining the sales forecasting methodology as it relates to the test year, comparing it to industry norms, and interviewed Company personnel responsible for the sales forecast.

Analysis

Blue Ridge's analysis of DEO's load forecasting process involved a number of steps. To understand the process of load forecasting, Blue Ridge reviewed the Company's written summary explaining the forecasting (sales) methodology[138] as it relates to the test year. Blue Ridge submitted initial pre-interview data requests to the Company to understand the basis for its forecasting process, developed structured questions for the planned interviews, determined the appropriate interviewees in conjunction with the Company and reviewed DEO's data responses available before the interview. Blue Ridge conducted an interview with Company personnel, took notes during the interview, developed and reviewed the interview notes, and developed and reviewed follow up data requests/responses. Blue Ridge compared and contrasted DEO's forecasting process to the best case or best practice load forecast process to determine whether any missing elements are material or relevant.

Blue Ridge determined that DEO uses trending[139] to prepare its five-year delivery forecast supplemented with information about approximately 100 of DEO's largest or important customers provided by the Company's Sales Department. The five-year forecast consists of two years by month and then annual estimates for the three following years. The forecast is loosely documented[140] and supported by a spreadsheet that receives data from extracts[141] taken from the Company's billing systems. The spreadsheet currently used by the incumbent was adopted from his predecessor.[142] The forecast is performed on a customer class basis by rate schedule. No economic data are used in the development of the forecast.[143]

The Residential and Non-Residential classes are forecasted using billing days, heating degree days ("HDD"), number of customers, daily base load and heating factor per HDD. The daily base load and heating factor are based on the twelve months of billing information extracted.[144] The number of customers is based upon a five-year history of growth.[145] As the charts below illustrates, usage per customer (residential and commercial) has had a downward trend.[146] This effect is not uncommon and Blue Ridge has seen this long-term trend at other gas utilities.

[138] Response to Data Request BRCS-HS-01-001.
[139] Blue Ridge did not review and confirm the input data, statistical regressions and other calculations inherent in the forecast and trend models as that investigation would be extensive.
[140] A single paragraph narrative supplemented by the first page of Supplemental Information C-12 defining the forecasting process was provided in the response to Data Request BRCS-HS-01-01.
[141] Testimony of Larry J. Rice (Case No. 07-829-GA-AIR) Q7.
[142] Rice - Interview on 080117 (10).
[143] Rice - Interview on 080117 (7).
[144] April 2006 through March 2007.
[145] Testimony of Larry J. Rice (Case No. 07-829-GA-AIR) Q8.
[146] Response to Data Request BRCS-HS-01-012 LJR Updated (1985 to present).

Figure 10: Normalized Residential Usage Per Customer 1985-2007[147]

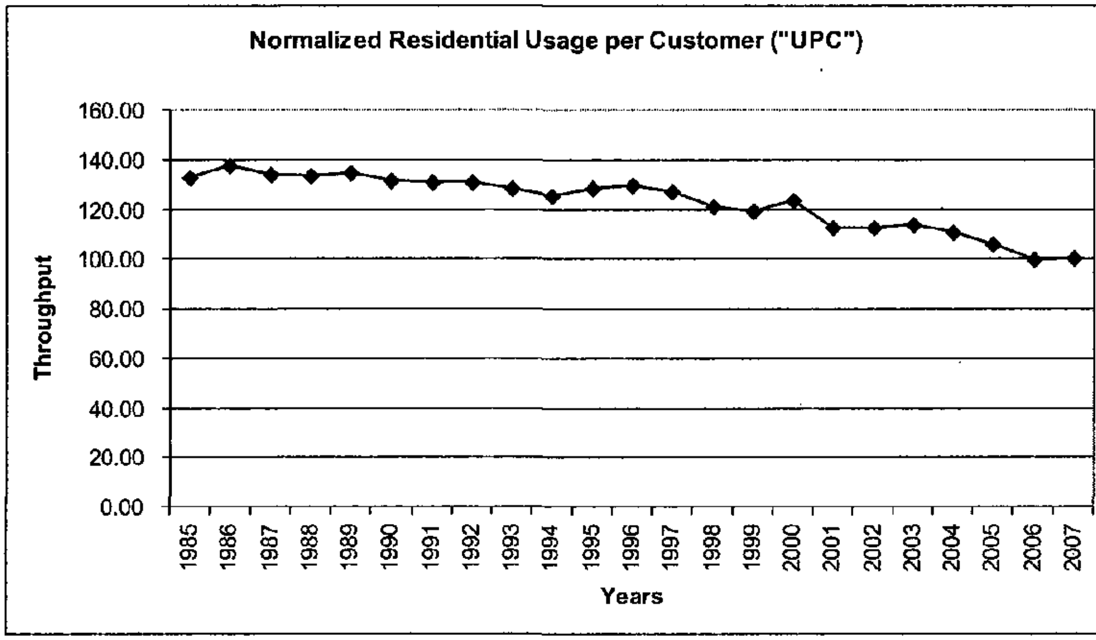
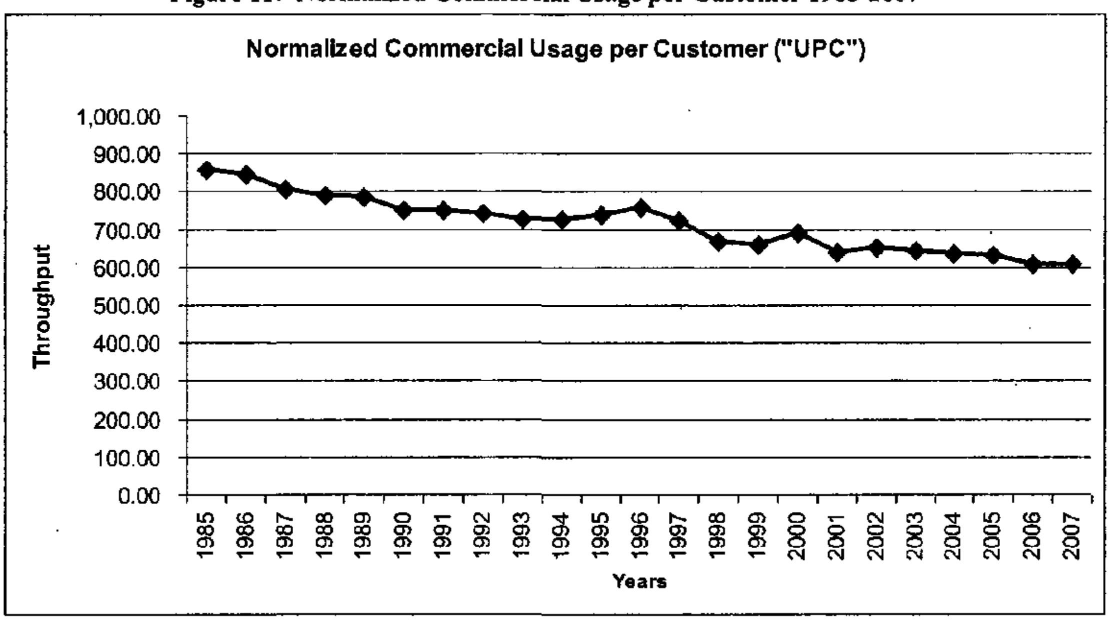


Figure 11: Normalized Commercial Usage per Customer 1985-2007[148]



DEO's approximately 100 largest customers' volumes are forecasted using a survey executed by the Sales Department. Blue Ridge reviewed the survey document.[149]

[147] Workpaper *B(11) Charts from HS_01_12LJR-Updated.xls.*
[148] Workpaper *B(11) Charts from HS_01_12LJR-Updated.xls.*
[149] The survey was provided in the response to Data Request BRCS-HS-05-02.

The Design Day forecast is driven by the highest daily value over the January through March period and is calculated on a class and rate schedule basis using regression techniques.[150]

Residential and commercial usage is weather normalized by assuming that the monthly usage for July and August represent base (non-weather affected) usage. The base usage is subtracted from each month's usage and divided by the actual monthly degree days to develop the heating factor per degree day.[151] Within the past five years, DEO moved to a seventeen-year rolling average of weather data. This change was driven by the Company's process of reviewing varying periods of moving averages to select the best fit (using the highest r-squared as the measure).[152]

Blue Ridge determined that DEO's trend models are static and have remained generally unchanged over the past few years. To date, DEO has begun assembling data necessary to backcast and validate its forecast; however, the data assembly only began in January 2006 and no significant validation has taken place. At Blue Ridge's request, the Company provided its annual backcasting results for 2006-2007.[153]

DEO's approval process for the forecast is rudimentary. No written approvals are required.[154] The forecast is compared to historical trends focusing on usage per customer and annual throughput by the Financial and Business Services group. Blue Ridge reviewed the response to a data request to determine the extent of changes, if any, made by DEO in the past. In late 2005, the Company increased the Residential conservation rate to reflect the impact of price increases due to Gulf hurricanes. No change was made to Non-Residential sales due to a lack of price data and the potential that commercial customers were using fixed or longer-term price arrangements.[155]

DEO indicated that no similar changes were made in preparing the forecast for this rate filing.[156] As the following table and graph demonstrates, there are a number of different forecasts for calendar year 2007,[157] which have evolved over time. There is a difference between the Company's 2007 Plan[158] and its 2007 Test Year[159] forecasts. For

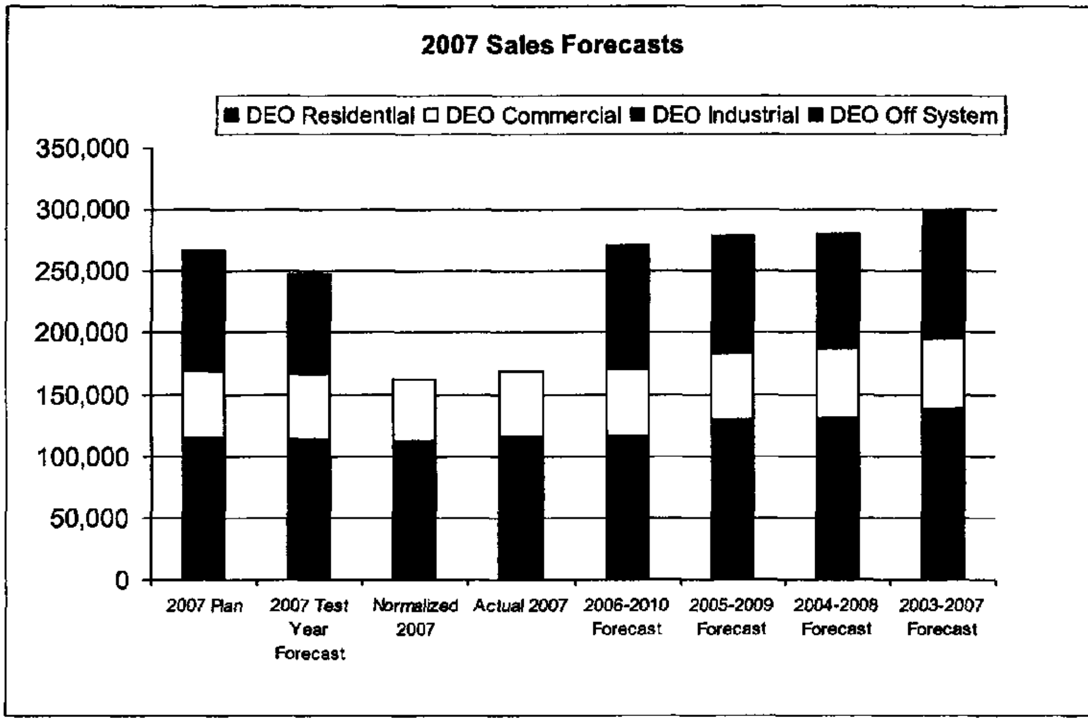
[150] The spreadsheet was provided in the response to Data Request BRCS-HS-05-01.
[151] Data Request BRCS-HS-01-009, the spreadsheet was provided in the response to Data Request BRCS-HS-01-12.
[152] Supplemental Information C-12 and GPR_01_16_Heating_Degree_Days LJR.zip.
[153] Data Request BRCS-HS-01-008. The spreadsheet providing the backcast information was provided in response to Data Request BRCS-HS-01-007.
[154] Response to Data Request BRCS-HS-01-006.
[155] Response to Data Request BRCS-HS-01-014.
[156] Response to Data Request BRCS-HS-05-004.
[157] Response to Data Request BRCS-HS-05-003, Volumes in 5 Yr Plan 2002-2006+HS.xls.
[158] Response to Data Request BRCS-HS-01-005 LJR JL.xls.
[159] Response to Data Request BRCS-HS-05-001 TEST_YEAR_FORECAST.xls.

comparison the actual 2007[160] and normalized (weather adjusted) 2007[161] sales have been included.

Table 14: Comparison of 2007 Forecasts and Sales[162]

	2007 Plan	2007 Test Year	Normalized 2007	Actual 2007	2006 - 2010 Forecast	2005 - 2009 Forecast	2004 - 2008 Forecast	2003 - 2007 Forecast
Residential	115,876	113,737	112,619	117,197	116,329	130,034	131,419	138,834
Commercial	53,554	52,655	50,302	52,305	53,487	53,608	58,165	57,095
Industrial	85,242	81,891			92,541	87,212	84,997	95,819
Off System	12,481				8,658	8,000	8,000	7,000
Total	267,154				271,015	278,854	280,581	298,748

Figure 12: 2007 Sales Forecasts



Blue Ridge determined that the Company's trending process does not explicitly contemplate the effects of price elasticity and relative gas prices (average and marginal).

The position descriptions for individuals involved with the load forecast were examined and Blue Ridge determined that none of the four position descriptions provided by DEO referred to or mentioned the load forecast process.[163]

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[160] Response to Data Request BRCS-HS-01-012 LJR Updated.xls.
[161] Response to Data Request BRCS-HS-01-012 LJR Updated.xls.
[162] Workpaper *B(11)_Charts from HS 05-03 Volumes in 5 yr plan 2002-2006-1+HS.xls.*

Formal written approval is not required before the forecast is sent to other departments.[164] Blue Ridge specifically asked whether there has been any pressure to change or modify the sales forecast or process. There has been no pressure or influence exerted, including specifically the forecast used for this rate case.[165]

Financial and Business Services converts the forecast volumes into revenue, which is used in DEO's budgeting process.

The Company's plans for improvement include taking the forecast analysis down to the billing cycle level in an attempt to better estimate the shoulder months.[166]

Findings

Approximately 90 to 100 Industrial customers are surveyed to provide input to the forecast.

The load forecast process is not well defined and loosely controlled. The position descriptions of the individuals involved in the development of the load forecast do not reflect this responsibility. The spreadsheet used to generate the forecast is not supported by detailed documentation.

Although forecasts are reviewed by the Business and Financial Services group, there is no formal written approval by senior management before the forecast is sent to other departments. Blue Ridge specifically asked whether there has been any pressure to change or modify the sales forecast or process. There has been no reported pressure or influence exerted. There appear to be no standards for the review and adjustment process.

Usage per customer has been on a downward trend similar to other gas utilities. However, the forecast used for this rate case does not include any specific adjustments other than the inherent trend process. However, there is a difference between the 2007 Plan and 2007 Test Year forecasts.

Conclusions and Recommendations

DEO's load forecasting process is a barebones trend analysis supported by spreadsheets developed before the incumbent individual responsible assumed the responsibility for the forecast. The process is not well documented. It lacks standards for internal review. The process does not provide attention to the complex nature of prices and elasticity. The Company's load forecast process, as detailed within its filing and the provided narrative, includes generally accepted processes. Blue Ridge believes that the results meet a

[163] Response to Data Request BRCS-HS-01-003 and BRCS Interview Larry J. Rice and Cliff Andrews (1/17/08) (4).
[164] Response to Data Request BRCS-HS-01-006.
[165] Rice - Interview on 080117 (26).
[166] Rice - Interview on 080117 (27).

minimum standard and are acceptable for the purpose of this ratecase. However, the weather normalization is based on a period of time that may change for each forecast.

DEO has a formalized survey process to ensure that large volume users have been surveyed, which improves the accuracy of the load forecast.

DEO should require formal approval by senior management of the load forecast based upon defined standards before it is distributed to other departments because it is one of the most important components of the business planning process.

The Company should consider documenting the load forecasting process and associated standards.

Operating Income Task B.13 and Rate Base Task C.15

Task B.13-Review the applicant's proposed adjustments to operating income and trace them to supporting workpapers and source data.

Task C.15-The auditor will review and analyze the Applicant's proposed adjustments to operating income and rate base and trace them to supporting workpapers and source data.

Background

The Company proposed numerous adjustments to test year operating income (revenues and expenses) and rate base, each of which Blue Ridge reviewed, verified for mathematical accuracy, and traced back to source documentation. Both sections Operating Income Task B.13 and Rate Base Task C.15 relate to the Company's proposed adjustments to the test year. Task B.13 addresses the review of the Company's proposed adjustments to test year operating income and tracing those adjustments to source documents and workpapers. Task C.15 addresses the review of the Company's proposed adjustments to operating income *and* rate base and tracing them to source documents and supporting workpapers. Due to the overlap between Tasks B.13 and C.15 of reviewing and tracing to source proposed adjustments to operating income, these tasks will be discussed together. In addition, as indicated in the work steps, a degree of overlap exists between these tasks and General Requirements Task A.3 related to verifying the mathematical accuracy of the Company's filing.

Blue Ridge performed a mathematical accuracy check of the proposed adjustments, identified hard-coded values, requested source documentation for hard-coded values,[167] reviewed the supporting documentation, and traced the adjustment inputs to the supporting documentation. Blue Ridge created an exceptions list for values that it could not verify in relation to supporting documentation.[168]

[167] Blue Ridge issued more than 50 data requests (some of which were multi-part requests) regarding source documentation for values in the Company's filing.
[168] See General Requirements Task A.3 of this report.

From the supporting documentation provided by the Company for its proposed adjustments, Blue Ridge created a pro forma backup book that provides supporting documentation necessary to trace each of the Company's proposed adjustments to its underlying source documentation, addressing each adjustment in a separate tab of the backup book.[169]

Analysis

Blue Ridge first identified the Company's proposed adjustments to operating income and rate base[170] and verified each of the calculations used to derive the numbers for mathematical accuracy and proper flow through the model. Blue Ridge requested and reviewed extensive discovery on the backup support for numerous values that are used in the formulation of the Company's proposed adjustments that could not be verified in Blue Ridge's preliminary analysis. Blue Ridge then traced the numbers underlying each of the adjustments back to their source documentation. Once the source documentation was located for a particular value, this source was logged into Blue Ridge's mathematical accuracy test workpapers[171] and that source document was added to the pro forma backup book. For any values underlying the proposed adjustments that could not be traced to supporting documentation, an exception was noted.

Blue Ridge created a backup book of the proposed adjustments, which is a book containing supporting documentation for the values that serve as the basis of the Company's proposed adjustments. This backup book is a PDF document with a separate tab for each adjustment to operating income and rate base.[172] The first page of each tab is a cover page, which identifies the purpose of the adjustment and the monetary value of the adjustment. The second page of each tab is the Company's summary of the proposed adjustment from the revenue requirement model.[173] The remaining pages of each tab contain the supporting documentation for the inputs that make up that proposed adjustment. The workpapers are annotated, showing the source of the data within the backup book. This backup book is designed to provide within one document all of the adjustments proposed by the Company to operating income and rate base (and the inputs that make up those adjustments) with the trace back to their source document(s).

Blue Ridge conducted interviews and follow-up discussions with Company personnel to verify the mathematical accuracy of the proposed adjustments and to assist in tracing the information to source documentation.

[169] Workpaper *B(13)_C(15)_ProForma Backup Book CONFIDENTIAL.pdf.*

[170] Those adjustments are found in the Company's revenue requirement model at Filename: *C-3 and 3.1.xls* Tabs C-3.1 through C-3.31; Filename: *B-2 Property Schedules.xls* Tabs B-2.2 pp. 1-6; Filename: *B-3 and B-3.1 Acc Depr by Acct.xls* Tabs B-3.1 pp. 1-5; and Filename: *B All Other Schedules.xls* Tab B-6.1.

[171] Workpaper *A(3)_Math. Accuracy Test.zip.*

[172] The tabs of the pro forma back up book are set up according to the operating income and rate base adjustments on Tabs C3.1 through C3.31, Tabs B-2.2, Tabs B-3.1 and Tab B-6 of the Company's revenue requirement model. That is, Tab C-3.1 of the back up book corresponds to adjustment C-3.1 of the Company's model.

[173] Workpaper *A(3)_Math. Accuracy Test.zip*, Filename: *C-3 and 3.1.xls.*

Findings

Blue Ridge's exceptions regarding mathematical errors in the Company's filing are discussed in section General Requirements Task A.3. The impacts of correcting those errors on the Company's proposed adjustments are summarized in the following table. Only adjustments that are impacted by the corrections are shown.

Table 15: Impact of Error Corrections on DEO's Proposed Test Year Adjustments[174]

Adjustment	"As Filed" Results	Revised Results	$ Change	% Change
C-3.1	$12,494,370	$12,494,390	$20	0.0002%
C-3.17	$1,176,731	$1,241,887	$65,156	5.54%
C-3.18	($275,007)	($275,089)	($82)	0.03%
C-3.23	($390,275)	($453,524)	($63,249)	16.21%
C-3.27	($2,500,000)	($3,000,000)	($500,000)	20.00%
C-3.30	($1,732,789)	($1,940,635)	($207,846)	11.99%
B-3.1	$62,823,124	$59,985,396	($2,837,728)	-4.52%

The table above displays the impact on the Company's proposed adjustments from correcting errors identified by Blue Ridge. Seven proposed adjustments have been found to be inaccurate. The impacted adjustments are listed and described below. The impact of these corrections on the Company's revenue deficiency is provided in section General Requirements Task A.3.

1. C-3.1: To synchronize calendar month gas costs with billed revenues to eliminate the timing differences through the date certain.
2. C-3.17: To adjust salary, wage, and benefit costs to reflect annualization of the merit increases and union wage increase effective in the test year.
3. C-3.18: To adjust test year taxes other than income to reflect payroll taxes on annualized wages, salaries, and benefits.
4. C-3.23: To eliminate public relations expenses from test year operating expenses.
5. C-3.27: To adjust test year operating expenses to remove the existing weatherization funding provided by ratepayers that will be replaced with increased Demand Side Management funding provided through amortization of the over-accrued depreciation reserve.
6. C3.30: To adjust the amount of other post-employment benefits included in test year operating expenses to reflect the latest actuarial study.
7. B-3.1 (page 2): To remove reserves associated with Asset Retirement Obligations recorded in accordance with SFAS #143 and related FASB Interpretation #47.

[174] Workpaper *A(3)_Math.Accuracy Test.zip,* Filenames *C3 and C3.1.xls* and *B3 and B3.1 Acc Depr by Acct.xls*. Response to Data Requests BRCS-WF-01-003 and BRCS-WF-03-024.

Conclusions and Recommendations

The errors discovered by Blue Ridge in the Company's model causes seven proposed adjustments to be inaccurate. Blue Ridge recommends that the Company make the corrections/updates listed above and in section General Requirements Task A.3 to the Company's proposed adjustments. The mathematical accuracy of the remaining adjustments to operating income and rate base are reasonably accurate.

C. RATE BASE

Audit Team

1. Michael J. McGarry – Lead
2. Donna Mullinax
3. Dan Salter
4. Patrick Phipps
5. Michael T. Dryjanski
6. Tracy Mullinax – Support

Audit Objectives and Scope

Blue Ridge's audit objectives and scope as provided in the approved work plan included an evaluation of the following:

Task C.1-The auditor selected shall prepare a balance sheet comparison of the date certain to actual historical financial data. The comparison shall include historic data for the most recent five years for which data is available to determine whether the rate base is representative of historical trends. Abnormalities in the date certain balance sheet shall be noted and investigated.

Develop a comparative analysis of balance sheet. Determine significant increases in rate base and investigated cause. Request support for/or explanation of significant increases.

Task C.2-The auditor selected shall prepare a comparison to identify plant additions by year, by account. Major additions shall also be identified by project description.

Request a list of major plant additions. Request project descriptions. Prepare summary report of major additions.

Task C.3-The auditor shall sample projects directed at the major additions since date certain in the previous case and examine work orders and other source documents. Primary efforts shall be directed toward the significant issues of the case.

Determine major plant related issues in case (known and certain: automatic meter reading). Select projects for review (at random). Develop a requirements list of supporting documentation for projects. Request and physically review project files including work orders and supporting documentation. Note any discrepancies or missing documents. Validate that supporting document is appropriate, valid and adequately supports costs being incurred. Note any exceptions.

Task C.4-The auditor shall conduct field investigations to physically inspect sample projects.

Schedule field visits to projects identified above. Conduct field visits noting project completion and whether the facility meets the Commission's standards for used and useful.

Task C.5-The auditor selected shall review major additions, retirements, transfers, and adjustments to current date certain value of plant in service that have occurred since the date certain from the last rate proceeding.

Request and prepare an analysis of additions, retirements, transfers and adjustments for the purpose of establishing the validity of current rate base level proposed in case.

Task C.6-The auditor shall review annual plant balances, plant retirements, and their corresponding salvage and cost of removal.

Request and prepare an analysis of annual plant balances, plant retirements, and their corresponding salvage and cost of removal for the purpose of reviewing accumulated depreciation amortization

Task C.7-The auditor selected shall review current Commission approved amortization of reserve deficiency (if applicable).

Request and understand the PUCO's current approved amortization of the reserve policies and rules. Assess whether the Company's filing complies with these policies and rules and note any exceptions.

Task C.8-*The auditor shall verify that plant retirements have been reflected in plant in service and depreciation reserve.*

Validate plant retirements have been appropriately reflected.

Task C.9-The auditor shall verify that amortization expense of capital leases corresponds with the capitalized amount and is amortized at the proper rate.

Request a list of capital leases. Validate proper recording on accounting system. Validate appropriate depreciation rate. Validate amortization calculation.

Task C.10-The auditor shall analyze Allowance for Funds used During Construction (AFUDC), or Interest Used during Construction (IDC) to ensure a proper calculation.

Request a list of projects currently in CWIP. Request company's procedures for applying AFUDC/IDC. Validate AFUDC/IDC rate calculation. Validate applicability of AFUDC/IDC to project list. Validate calculation of AFUDC/IDC on project list.

Task C.11-Any major sale of plant or equipment since the Applicant's last base rate case shall be reviewed to determine if gains or losses from the sale are treated properly.

Request a list of sale of major plant equipment (greater than ($100,000). Request and review transaction report and journal entries related to list. Note amounts of gains and losses and follow through to GL. Validate appropriate amounts flowing through to income statement/balance sheet as appropriate. Note any exceptions.

Task C.12-The auditor shall verify the Applicant's inventory of Material and Supplies (M&S) included in the application is for repair or replacement of existing plant and equipment and not for construction projects.

Request list of M&S making up the inventory balance included in the company's filing. Develop a list of "what should be there" for select store rooms. Request field visit of select store rooms and physically inspect inventory looking for presence of specified M&S. Interview store keepers to determine the layout of stores and how M&S is differentiated repair/replace and construction. Note possible exceptions.

Task C.13-The auditor shall become familiar with any regulatory assets, the nature of the entries, dollar amounts, reason for the deferrals, and whether regulatory approval has primarily been obtained for the deferrals.

Request list of all regulatory assets and the underlying basis. Determine which have specific regulatory approval. Note any exceptions.

Task C.14-The auditor shall investigate the accounting for income taxes and verify that the Applicant has properly accounted for the differences on the balance sheet.

Review the tax accounting procedures/rules for Ohio. Review and validate Company's underlying calculations and underlying support documentation. Note any possible exceptions.

Task C.15-The auditor will review and analyze the Applicant's proposed adjustments to operating income and rate base and trace them to supporting workpapers and source data. [175]

Validate the company's revenue requirement calculations and linkage to backup supporting document and note any exception.

[175] Due to the similarities between Task B.13 and Task C.15, they will be discussed together in this report. See the discussion for Task B.13 in Section B. Operating Income of this report.

Task C.16-Other independent analyses will be performed as the auditor and/or Staff consider necessary under the circumstances.

See the Section labeled Other Independent Analysis.

Rate Base Task C.1

Task C.1-The auditor selected shall prepare a balance sheet comparison of the date certain to actual historical financial data. The comparison shall include historic data for the most recent five years for which data is available to determine whether the rate base is representative of historical trends. Abnormalities in the date certain balance sheet shall be noted and investigated.

Background

The Company is obligated to provide the information related to its assets and liabilities in a manner by which the Commission and interested parties can evaluate the Company's investments in those assets that are being used to service customers directly (i.e., gas plant in service) and indirectly (i.e., common plant, such as offices and related administrative space, and intangible plant, such as computer systems). In addition, other balance sheet asset items, including current and accrued assets (e.g., cash, prepayments, accounts receivable, working funds, materials and supplies, etc.) are examined for their inclusion and/or effect on rate base. The liabilities are important to understand the way the Company's debt and other obligations are structured so that rates are set to provide sufficient interest coverage.

Analysis

As part of the auditors' review of the mathematical accuracy of the Company's revenue requirement calculations, Blue Ridge reviewed and validated all mathematical computations and data included in the balance sheet.

Blue Ridge reviewed the Revenue Requirements Model provided by the Company, including Schedule C11.1,[176] which provides a balance sheet comparison of "Date Certain" balances and year-end balances for each of the calendar years 2002 through 2006.

The following table shows the aggregate balance sheet comparison.

[176] Standard Filing Requirement, Schedule C11.1.

Table 16: Comparative Balance Sheet[177]

THE EAST OHIO GAS COMPANY d/b/a DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Comparative Balance Sheets (Total Company)
As of March 31, 2007 and December 31, 2002 - 2006

Source: Schedule C-11.1

Line No.	Description	Date Certain 3/31/2007	Most Recent Five Calendar Years 2006	2005	2004	2003	2002
1	**Assets And Other Debits:**						
2	Utility Plant						
3	Net Utility Plant	1,159,237,346	1,158,008,678	1,113,783,648	1,016,444,244	985,410,024	947,829,405
4	Gas Stored Underground - Noncurrent	22,491,371	22,491,371	22,510,483	22,644,270	22,644,270	22,644,270
5	Total Utility Plant	1,181,728,717	1,180,500,049	1,136,294,131	1,039,088,514	1,008,054,294	970,473,675
6	Other Property And Investments	3,317,109	3,317,109	3,326,430	3,325,992	3,499,120	3,489,745
7	Current & Accrued Assets	693,122,706	518,742,504	738,389,915	457,240,351	378,489,582	293,350,099
8	Deferred Debits	911,252,950	865,541,402	821,624,737	630,666,772	572,496,957	506,301,508
9	**Total Assets And Other Debits**	$2,789,421,482	$2,568,101,064	$2,699,635,213	$2,130,321,629	$1,962,539,953	$1,773,615,027
10	**Liabilities And Other Credits**						
11	Total Proprietary Capital	917,731,470	904,672,485	532,271,916	522,045,954	499,609,061	482,032,145
12	Long Term Debt	674,835,900	674,835,900	199,585,900	201,335,900	203,277,500	260,717,800
13	*Total Other Non-Current Liabilities*	*127,609,067*	*77,758,028*	*74,255,620*	*20,423,212*	*21,956,179*	*23,874,226*
14	Total Current & Accrued Liabilities	603,285,123	443,521,908	1,444,398,673	1,001,813,258	874,828,910	674,300,077
15	Deferred Credits	465,959,920	467,312,742	449,123,103	384,703,304	362,868,303	332,690,779
16	**Total Liabilities & Other Credits**	$2,789,421,480	$2,568,101,063	$2,699,635,212	$2,130,321,628	$1,962,539,953	$1,773,615,027

Findings

Blue Ridge found that the balance sheet comparison reflects historical trend except in year 2005, which showed an overall increase from the previous year of about $540 million (a 27% increase). The increase is found mostly in the asset account Prepayments offset by the liability account Payables to Associated Companies.

Conclusions and Recommendations

Blue Ridge concludes that the balance sheet as presented in the Revenue Requirements Model (Schedule C11.1) for the most part reflects historical trend. The anomaly in 2005 does not impact the trend for 2006 and beyond.

Rate Base Task C.2

Task C.2-The auditor selected shall prepare a comparison to identify plant additions by year, by account. Major additions shall also be identified by project description.

Background

Through the rate case process, a utility is allowed the opportunity to earn a return on its investment in those assets that are deemed "used and useful" in serving the needs of the regulated utility's customers. The utility typically makes the investment in the assets, constructs the facilities and places them in service before seeking approval to include those assets in rate base and thus be allowed an opportunity to earn a return on that investment. The rate case process is a cumulative process wherein previously approved assets are presumed used and useful until their retirement or transfer from rate base.[178]

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[177] Workpaper *C(1)Balance Sheet Comparison.xls.*
[178] Transfers can occur because of, among other things, the sale of the asset.

However, plant additions between rate cases are of special interest since these assets have not been reviewed as to whether they are used and useful to the utility's customers.

This task identified those asset amounts that have been added to DEO's plant in service since its last rate case.

Analysis

The last rate case was conducted in 1993 and Dominion's merger with Consolidated finalized by 2000. However, due to the Company's other merger history, Blue Ridge divided its review of the plant asset activity into three time period sections—1983 to 1996 (Cat 1 - West activity), 1997 to 1999 (Cat 2 - East/West combined activity), and 2000 to 2007 (Cat 3 - DEO merged activity). The Cat 1 – West activity was useful only as a basis or starting point to see how later data evolved.

The Standard Filing Requirements provided by the Company show current plant asset balances and cumulative activity for the East from 1994 to 1996, for the West from 1982 to 1996, and combined from 1997 to date certain March 2007.[179] However, these plant asset balances did not provide the detailed breakdown of account additions, retirements, and adjustments from year to year. Blue Ridge identified two other sources for its examination of the year to year detail changes. These included (1) the annual report information (AR) supplied by Staff and (2) the Company filing Volume 7, Supplemental #18 (Supp 18).

Blue Ridge first compared these two information sources to determine whether any discrepancies existed.[180] In time period Cat 1, no discrepancies occurred. In Cat 2, adjustments are made in Supp 18 during the years 1997 to 1999; however, total plant balances remain the same. From 2003 to 2006, minor differences exist between AR and Supp 18 due to the manner of recording of Asset Retirement Obligations. However, by 2007, adjustments were made to Supp 18 accounting so that Supp 18 equals the amounts in AR.

Using the information from the Staff-supplied AR, Blue Ridge developed a reorganized spreadsheet to compare year-to-year changes.[181] Plant assets have increased by a small percentage each year during the thirteen years since the last rate case—from 1,245,969,855 in 1993 to 1,933,453,697 in 2006. The greatest increase took place in 1999 with a 7.32% rise. The most recent year of evaluation (2006) boasted only a 0.81% increase over the previous year.

Plant additions averaged about $72 million each year since the last rate case in 1993. The following table reflects the plant additions comparison by year and FERC Account.

[179] Standard Filing Requirement, Schedule B-2.3.
[180] Workpaper *C(2) Plant Assets.xls*, tab *Source Comparison.*
[181] Workpaper *C(2) Plant Assets.xls*, tab *Trend-AR Combined.*

Table 17: Plant Asset Additions since 1993[182]

COMPANY ACCT DESCRIPTION	FERC ACCT NO	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
INTANGIBLE PLANT														
Organization	301	30,132	104,423	3,527,846	0	0	0	0	0	0	0	0	0	0
Franchise & Consents	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous	303	0	7,298,565	3,007,191	3,143,274	962,567	68,346,789	19,894,641	8,903,074	-302,650	2,786,470	5,493,669	5,817,551	3,153,500
TOTAL		30,132	7,402,988	6,534,837	3,143,274	962,567	68,346,789	19,894,641	8,903,074	-302,650	2,786,470	5,493,669	5,817,551	3,153,500
PRODUCTION PLANT														
Rights of Way	325.4	4	10,405	3,359	1,197	0	0	0	0	4,363	750	18,163	26,861	77,009
Other Land/Land Rights	325.5	0	0	1,297	0	0	0	694	0	0	0	2,348	26,594	0
Field Compr Sta Struct	327	0	0	94,159	1,118	21,736	11,141	-11,141	0	0	0	178,204	0	12,733
Field Meas & Reg Sta	328	13,187	0	0	9,033	4,796	0	1,225	0	0	0	0	5,121	0
Other Structures	329	0	0	0	0	0	0	4,269	0	41,690	-6,349	0	0	0
Well Construction	330	65	0	0	0	0	0	0	0	0	0	0	0	0
Well Equipment	331	4,513	0	0	0	0	0	0	0	0	0	0	0	0
Field Lines	332	687,646	770,055	386,266	605,693	292,169	191,530	-350,177	558,560	492,171	441,095	1,319,304	2,537,560	1,350,541
Field Compr Sta Equip	333	*133,150*	*117,552*	*64,252*	*45,866*	*68,429*	*335,092*	*25,145*	*154,509*	*147,440*	*207,388*	*3,655,506*	*1,102,789*	*911,124*
Field Meas & Reg Equip	334	468,071	223,939	148,665	198,230	33,633	121,829	171,355	179,201	214,477	173,972	302,260	137,759	447,377
Drilling & Cleaning Equip	335	31,875	21,409	84,951	4	0	0	0	0	0	0	0	0	0
Other Equipment	337	0	0	0	0	0	0	0	0	0	8,843	0	0	0
Unsuccessful Expl Costs	338	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL		1,358,511	1,143,360	782,839	860,941	420,763	659,592	-158,630	892,270	900,141	825,699	5,373,784	3,838,664	2,798,784
U/G STORAGE PLANT														
Land	350.1	0	0	0	0	0	0	20,631	0	0	0	0	0	0
Leaseholds	350.2	-20,949	514	0	0	34,830	0	0	0	4,806	-3,663	2,889	-2,889	25,797
Rights of Way	350.4	4,899	0	0	0	0	0	0	0	0	0	0	0	0
Struct & Improvements	351	109,869	40,824	199,170	134,284	107,337	83,978	79,856	27,673	66,731	56,553	192,259	356,880	146,386
Wells	352	0	0	0	0	0	39,647	1,682,040	566,874	840,003	253,199	726,731	1,108,419	272,836
Strg Leasehold & Rights	352.1	485,270	530,135	488,645	677,105	631,501	0	46,838	0	0	0	0	1,324	0
Reservoirs	352.2	461,102	389,582	457,897	316,855	131,612	0	0	0	0	0	0	0	0
Lines	353	520,607	354,426	283,316	314,203	292,300	260,045	517,880	442,307	308,714	544,593	1,358,713	1,652,268	1,931,732
Compressor Sta Equip	354	543,845	816,416	479,887	1,765,719	547,928	798,356	-175,613	1,038,655	1,291,341	-155,113	3,348,920	1,148,454	1,939,109
Meas & Reg Equip	355	338,925	180,145	447,358	309,007	109,530	164,565	713,919	253,321	381,302	407,054	225,138	342,566	408,347
Other Equipment	357	14,134	0	0	9,980	183	0	-183	0	30,394	52,175	156,311	50,097	27,932
TOTAL		2,447,702	2,112,042	2,356,275	3,526,963	1,855,221	1,336,591	2,885,368	2,328,730	2,923,291	1,154,898	6,010,961	4,657,116	4,741,939
TRANSMISSION PLANT														
Land & Land Rights	365.1	0	0	1,699	0	10,008	0	2,696	0	0	0	0	0	0
Rights of Way	365.2	8,315	61,360	144,824	669	71	0	3,530	171,033	93,534	2,434	7,248	2,996	228,690
Struct & Improvements	366	147,212	31,228	57,516	105,745	23,708	11,946	65,969	103,326	22,697	160,309	98,261	211,290	154,034
Mains	367	1,253,164	1,382,571	1,684,710	2,993,910	1,968,202	1,879,983	1,283,192	2,084,683	4,060,343	3,733,262	4,424,328	5,514,244	3,569,549
Compressor Sta Equip	368	0	0	0	0	0	0	0	0	0	0	1,758,689	69,370	8,936
Meas & Reg Sta Equip	369	1,155,397	657,918	1,133,952	634,177	899,839	870,657	945,593	2,795,836	1,340,089	983,560	1,039,141	2,327,481	1,529,425
Other Equipment	371	12,965	1,346	35,149	2,738	0	152,470	202,134	8,645	0	-191,790	60,266	0	4,638
TOTAL		2,577,053	2,134,423	3,057,850	3,737,239	2,901,828	2,915,058	2,533,114	5,163,527	5,506,663	4,687,775	7,377,933	8,125,381	5,495,272
DISTRIBUTION PLANT														
Land & Land Rights	374	245,596	56,806	26,620	96,472	68,926	46,480	132,090	136,403	275,183	254,772	188,128	221,581	155,607
Structures & Imprvmnts	375	2,283,535	4,432,897	417,381	978,300	241,737	79,936	2,249,103	1,309,243	16,111,004	5,002,392	853,741	775,481	973,838
Mains	376	23,224,686	25,341,632	20,745,996	26,969,040	21,934,160	21,466,108	22,845,632	18,776,077	21,230,629	26,629,999	22,823,593	31,270,588	29,793,292
Meas & Reg Sta Equip	378	1,124,660	1,222,869	822,603	1,045,637	2,250,210	691,699	2,383,022	438,159	2,118,840	687,909	1,383,359	1,058,789	2,128,970
Services	380	9,524,703	8,801,373	9,371,582	10,245,176	11,429,937	10,687,428	11,146,503	9,344,315	13,613,950	15,950,598	18,880,292	15,906,369	14,441,730
Meters	381	3,788,429	3,103,060	5,420,558	4,409,617	5,499,157	1,606,195	4,906,253	2,145,805	3,268,487	4,573,013	4,877,919	2,558,792	7,128,820
Meter Installations	382	85,798	54,537	26,936	71,093	5,392	673,018	83,804	1,745,799	3,500,313	5,486,695	5,314,117	5,435,753	5,496,220
House Regulators	383	1,138,612	1,184,661	966,900	1,221,603	102,726	398,115	2,299,763	320,444	362,901	469,817	505,627	288,115	238,780
House Reg Installations	384	*35,014*	*39,685*	*33,775*	*35,109*	*0*	*0*	*17,114*	*0*	*184,505*	*179,180*	*40,098*	*63,291*	*20,726*
Indus Meas & Reg Equip	385	231,535	168,583	15,852	186,249	4,876	29,859	266,846	8,685	-3,492	59,954	885	792,848	80,826
Other Equipment	387	0	0	0	35,105	692,761	48,717	110,874	46,124	358,798	163,766	140,636	191,041	845,236
TOTAL		41,682,566	44,406,005	37,838,203	47,313,601	42,229,802	35,617,555	46,320,524	34,271,054	81,019,118	61,448,295	55,008,393	58,560,625	61,308,025
GENERAL PLANT														
Land & Land Rights	389	0	162,552	0	0	0	0	-116	0	9,558	1,822	0	0	0
Structures & Imprvmnts	390	21,960	460,456	103,162	0	0	0	0	0	95,647	459,486	180,745	243,786	167,164
Office Furniture & Equip	391	425,164	621,962	192,136	172,728	3,521,706	52,043	1,893,214	618,427	1,544,297	78,505	277,964	51,258	629,857
Comp Under Cap Lease	391.2	0	0	0	0	0	0	0	0	-12,258	0	0	0	0
Transportation Equip	392	*1,860,270*	*2,104,119*	*398,642*	*134,550*	*1,038,368*	*2,151,418*	*953,931*	*254,487*	*-106,630*	*124,797*	*43,436*	*75,778*	*241,538*
Stores Equipment	393	6,020	109	0	0	0	0	258,050	0	0	0	0	0	0
Tools, Shop & Grg Equip	394	1,826,901	1,844,316	1,655,939	1,035,353	619,538	469,836	4,082,627	229,880	38,245	57,590	-17,473	-3,662	105,630
Laboratory Equipment	395	29,325	56,286	3,579	0	0	0	0	0	0	0	0	0	0
Power Operated Equip	396	1,147,670	445,871	621,398	563,572	84,638	681,421	-2,662,584	838,252	862,617	764,065	350,171	110,598	703,465
Communication Equip	397	2,835,312	5,424,613	2,692,053	4,602,612	496,353	70,986	1,048,342	89,622	3,130,200	2,430,723	3,131,799	896,798	532,740
Miscellaneous Equip	398	180,606	142,685	19,657	88,447	8,912	181,516	92,356	0	106,715	69,136	0	5,100	16,124
Other Tangible Property	399	0	0	0	0	0	0	0	0	0	0	305,209	1,387,417	45,916
Asset Recovery Costs	399.1	0	0	0	0	0	0	0	0	0	0	0	0	5,125,738
TOTAL		8,333,228	11,254,953	5,684,566	6,597,162	5,869,513	3,607,018	5,645,819	1,931,468	5,687,393	3,986,124	4,271,651	2,786,876	7,768,190
ANNUAL TOTAL		66,429,192	68,453,771	58,254,570	65,179,170	54,239,794	112,482,803	77,120,838	53,490,123	75,733,956	74,889,261	83,636,591	83,768,213	85,263,710

182 Workpaper *C(2) Plant Assets.xls*, tab *Additions*.

Discussion of major projects is included in Rate Base Task C.3.

Findings

Blue Ridge found that plant additions as a whole have been consistent since the last rate case.

Conclusions and Recommendations

Conclusions and recommendations related to Plant Assets are specifically addressed in relation to the other tasks in the Rate Base section of this report

Rate Base Task C.3

Task C.3-The auditor shall sample projects directed at the major additions since date certain in the previous case and examine work orders and other source documents. Primary efforts shall be directed toward the significant issues of the case.

Background

The utility business, by its nature, is a capital intensive operation. Assets are purchased, constructed, and installed to serve generations of customers. As such, the Company's investment in plant is a major driver behind a rate case and affects the two major contributors to its revenue requirement—the return on investment and depreciation expense recorded in the operating expenses of the Company.

The purpose of this task is to validate that the major additions to the Company's plant in service since the rate case have been documented appropriately and recorded accurately on the Company's books and records. Therefore, it is necessary to investigate the details of the plant-in-service additions in order to determine that these additions are used and useful and are properly classified.[183]

As presented in its applications, the Company neither detailed major plant additions in the supporting schedules nor specifically addressed them in testimony. DEO merely summarized these additions in the Standard Filing Requirement Schedule B-2.3 and supporting workpapers. To validate the cost information contained in DEO's filing, Staff requested a review of the supporting work orders.

Analysis

Because of the volume of records, the PUCO Staff, in its design of the project, recognized that Blue Ridge would randomly sample the documentation to test for compliance with accepted accounting methods and standards. Blue Ridge focused on the Company's plant additions for the period from the last rate case to the date certain of March 31, 2007.

[183] Commonly referred to as "continuing property records" or CPR.

DEO's last rate case was in 1993.[184] However, as a result of mergers, Blue Ridge had to categorize the Company's plant additions evaluation according to three separate time periods. These periods are (1) from 1/1/1983, the date of West Ohio Gas's last submitted rate case, through 1996 when East Ohio Gas and West Ohio merged; (2) from 1997 through 1999, and (3) from 2000, when the merged East/West Ohio Gas Company then merged with Dominion, through the date certain of March 31, 2007. Effectively, DEO has not filed for a base rate increase for almost 15 years and, for a portion of its service territory (i.e., the former West Ohio Gas), not for 25 years.

This span of time and multiple mergers presented challenges for both the Company and Blue Ridge. First, the Company no longer has access to legacy accounting systems that contained the detailed records of the plant additions, thus limiting the review to archive records for the periods prior to 1998.[185] As part of Operating Income Task B.13 and Rate Base C.15, Blue Ridge validated the accuracy of the data contained in the Company's primary application and filing, supplemental information, and work papers, including Schedule B-2.3 and its supporting schedules. These schedules and supporting documents included summaries for each of the three periods.

To sample the documentation of capital projects for the period since the 1993 rate case through the date certain of March 31, 2007, Blue Ridge established a dollar threshold of $100,000[186] for the identification of major work orders. Blue Ridge requested specific work order information including, but not limited to, work order identification (i.e., WO or project number and WO Title), start date, completion/in-service date, original cost estimate, approved budget amount, summary of costs closed to plant, and cost of retirements.[187]

Due to the length of time from the last rate case (1993) to this one, the Company provided multiple files which contained the data.[188] The information provided showed that 484 work orders totaling $240.8 million met the $100,000 threshold criterion. This population of work orders represented 31% of the total plant additions, excluding the value of gas in storage since the Company's last rate case in 1993.

[184] Case No. 93-2006-GA-AIR.
[185] Response to Data Request BRCS-MTD-01-006 (subpart: 1994-1997).
[186] Data Requests BRCS-MTD-01-006 and BRCS-MTD-01-007.
[187] Data Requests BRCS-MTD-01-006 and BRCS-MTD-01-007.
[188] Response to Data Request BRCS-MTD-01-006, attachments MTD 01-6 Oracle 1998-2000.xls; MTD 01-6 SAP 2001-2007.xls; MTD 01-6 Oracle 1998-2000.xls; MTD 01-6 SAP 2001-2007.xls; [MTD 01-05]_[1994-1997].pdf; [MTD 01-06]_[1994-1997].pdf; [MTD 01-07]_[1994-1997].pdf; [MTD 01-08]_[1994-1997].pdf; [MTD 01-17]_[1994-1997].pdf; 1994-1997 SALE.xls; Accounting Entries.pdf; AFUCD1994-1997.xls; Plant Transactions 1994-1997.xls.

Table 18: Table : Plant Additions Work Order Summary[189]

Line	Classification		Additions	Source:
1	Production	$	18,873,447	B-2.3 - Gross Plant Activity.xls/Tab: Combined Prod - cell: E34
2	Storage**	$	31,974,528	B-2.3 - Gross Plant Activity.xls/Tab: Combined Storage - cell: E37
3	Transportation	$	48,455,950	B-2.3 - Gross Plant Activity.xls/Tab: Combined Trans - cell: E32
4	Distribution	$	523,825,401	B-2.3 - Gross Plant Activity.xls/Tab: Combined Distr - cell: E47
5	Genral	$	115,649,686	B-2.3 - Gross Plant Activity.xls/Tab: Combined Genl - cell: E48
6	Intangible	$	48,794,060	B-2.3 - Gross Plant Activity.xls/Tab: Combined Intang - cell: E23
7	Total Plant (excluding Gas in Storage)	$	787,573,072	Plant Transactions 1994-1997.xls]1994'!$H$25, Plant Transactions 1994-1997.xls]1995'!$G$25, Plant Transactions 1994-1997.xls]1996'!$G$29, Plant Transactions 1994-1997.xls]1997'!$G$34, MTD 01-06 CWOs $100k (Oracle1998-2000).xls]Appropriate >100000'!$J$152, WP_C3C5_X0_MTD 01-06 CWOs $100k (SAP2001-2007).xls]Sheet1'!$J$272
8	Work Orders GT $100,000	$	240,820,498	
9	Percent		30.58%	

As shown in the table above, the Company's plant additions are segmented into six major functional classifications. These classifications are:

- Production
- Storage
- Transportation
- Gas Distribution Plant
- Gas General Plant
- Intangible Plant

Blue Ridge analyzed the information provided and determined that a statistical valid sample of 38 projects would be required to evaluate the completeness of the work order information and determine whether plant-in-service costs were reasonably accurate and verifiable. Blue Ridge randomly selected 38 projects to test the procedural and documentation requirements for the work orders. In reviewing the data, the auditor also determined that one of the sample projects—project 400429 (Customer Accounting and Marketing Project)—was made up of 5 work orders that totaled $62.2 million in 1999 and, thus, warranted further review. As a result, Blue Ridge requested documentation to support 42 projects. The selected work orders included those which encompassed Blue Ridge's field reviews[190] and provided a cross section of work orders in each of the functional categories listed in the table above. The selected list was designed to cover a broad range of the subject plant accounts (i.e., FERC plant accounts).

For the 42 selected work orders, Blue Ridge requested documentation to determine that the Company managed, maintained, monitored, and controlled the information and costs of theses major additions. Information requested for the sampling of the work orders included:

[189] Workpaper *C(3) Sum of WO gt 100k 94-07.xls.*
[190] See section Rate Base Task C.4 of this report.

- Original and revised cost estimate information and budget
- Justification documents
- Project management, status, engineering, and budget variance reports
- Summary of costs closed to plant-in-service
- Breakdown of costs by major cost components, i.e., outside contractor labor, internal labor, materials, etc.
- Summary of cost of retirement
- Amount of plant retired, if appropriate

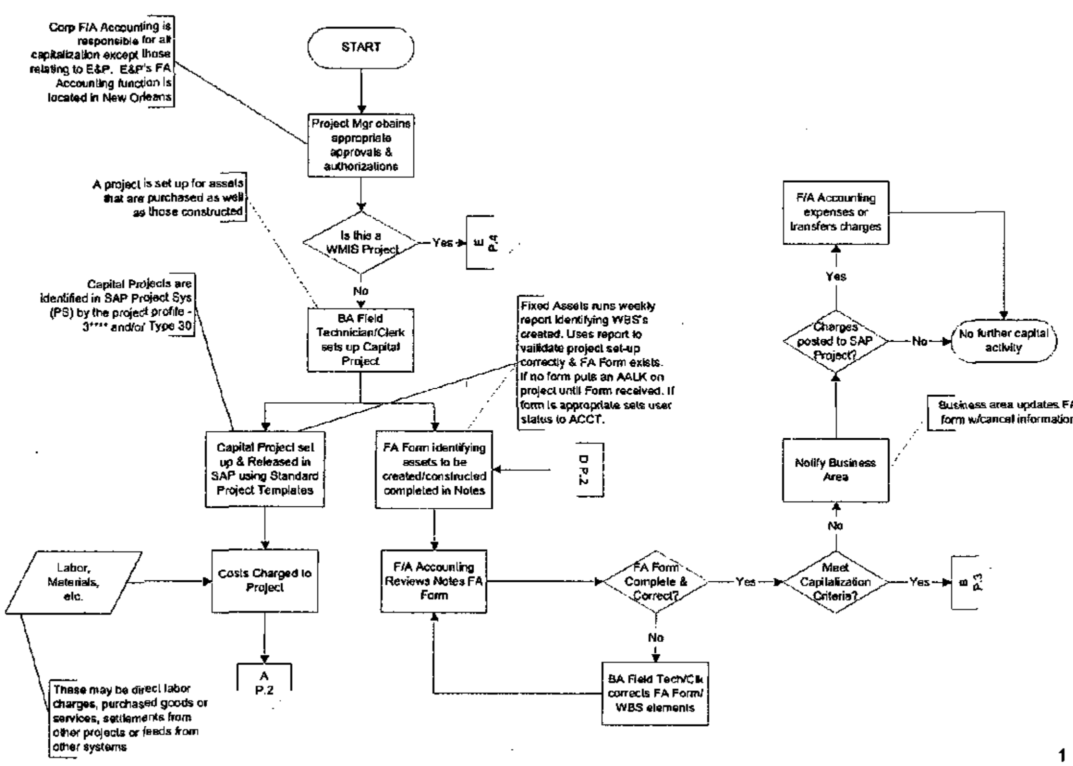
Blue Ridge selected transactions from each of the 42 sampled work orders to obtain a cross section of charge types such as direct and indirect labor, overheads, materials and supplies, and others. Blue Ridge requested documentation supporting these cost transactions for the additions as well as the retirements for overheads, charge backs, company material, contract labor, contract material, company payroll / labor, labor special payments, non-stock material, journal entry transactions, and outside services to ensure a sampling of source document types. This documentation was then reviewed and evaluated for compliance to generally accepted accounting principles.

Findings

The Company provided documentation that adequately supported the plant additions made by the 42 projects. This documentation included screen shots of the status and transactional summaries from its SAP system, a summary report in Excel format, available justification documents, and any related project management reports for several of the work orders in the sample. Blue Ridge's review indicates that the Company has well-documented fixed asset procedures.[191] In addition, the Company provided a detailed process flowchart which illustrates the fixed asset accounting process. A portion of that illustration is shown below.

[191] Responses to Data Requests BRCS-GRP-01-003 and BRCS-MTD-01-030.

Figure 13: Fixed Asset Accounting Process Map[192]
(page 1 of 5)
GAS ASSET CAPITALIZATION PROCESS



From detail project information provided for the sample, Blue Ridge identified various intervals through the course of the projects at which times the Company had posted cost information.

A significant portion of the plant additions for 2000 to 2007 included work completed through the blanket order process. Typically, this type of work order includes activities which are recurring, usually of short duration, and do not exceed certain dollar expenditure limitations. Customer installations, meters, and distribution main replacements are typical of the types of plant additions in which blanket work orders are used.

DEO does not, however, set a dollar limit for individual transactions that may be charged to blanket work orders.[193] For the period 1998 through date certain (March 31, 2007), blanket work orders accounted for $352 million[194] of the total plant additions of $787.6

[192] Response to Data Request BRCS-MTD-01-024.
[193] Green & White - Interview on 071219.
[194] Workpaper *C(3) BWO additions (from MTD-02-005) 1998-2007.xls.*

million.[195] Of this, $315 million (89.6%) was spent on those categories mentioned above, i.e., distribution main and customer installation-related work.

In reviewing the project cost and related documentation files, Blue Ridge found that the Company's documentation appears to adequately support the justification of expenditures and expenditures are accounted for in a timely fashion. Notable, however, is the lack of readily obtainable project documentation for projects prior to 1998. Furthermore, considerable difficulty occurred in amassing the data in a form that could be used for evaluation purposes to tie information from the audit to the Company's filing. The Company provided numerous data sources which had to be aggregated and matched to each other in order to perform the analysis.

Conclusions and Recommendation

The Company generally maintains a reasonably supportive set of documents for specific work orders. For plant additions, supporting cost files reasonably match summary information provided in response to the sample request. However, as part of its next rate filing, the Company should be prepared to demonstrate the tie-in of information from the supplemental filing to detail project and backup cost information.

Should they not file for an extended period, the Company should be on notice that its data retrieval capabilities need to allow for review of specific project information even though dated.

Rate Base Task C.4

Task C.4-The auditor shall conduct field investigations to physically inspect sample projects.

Background

Field visits are complementary to the accounting portion of the rate base audit. The field visits are designed to verify physically that the assets exist and are operational. Field visits are limited somewhat when the assets are located underground as would be expected for a gas utility. Field visits were selected for both physical assets and intangible assets, such as computer systems, based on the sample projects selected in Rate Base Task C.3.

Analysis

Blue Ridge conducted twenty-eight field visits of sample projects, including twenty physical site visits and eight intangible (software) reviews.[196] Documentation and site pictures, of which this section includes some, are located in Appendix 1. The sites were chosen based on a combination of cost, type of asset (production, transmission, intangible, etc.), date (to ensure review of projects completed at various times throughout

[195] Workpaper *C(3) Sum of WO gt 100k 94-07.xls.*
[196] Workpapers *C(4)Field Visit List.xls* and *C(4) Field Visits.doc.*

the between-rate-case time period), and location (to ensure review across the entire service territory). For discussion, these projects are grouped into seven categories: (1) Structures and Improvements, (2) Compressor Stations and Equipment, (3) Measuring / Regulating Stations and Equipment, (4) Communication Equipment, (5) Mains, (6) Wells, and (7) Intangible – Software.

1. Structures and Improvements
    a. Field Visit 1 – 55th Street Main Building – Cleveland
    b. Field Visit 2 – 55th Street Back Building – Cleveland
    c. Field Visit 3 – Clayton Ave. Office/Warehouse
    d. Field Visit 6 – Akron Call Center

    Blue Ridge examined the scope, justification, and contingencies of the structural improvement sample projects. Both 55th Street buildings were renovated from warehouses to house the main offices of DEO, providing a centralized location and relieving the necessity of leasing office space in downtown Cleveland. The conversion of warehouse to office covered almost 150,000 square feet, involving windows, walls, flooring, restrooms, electrical, HVAC, generator, computer server room, security, and handicap accessibility. Besides offices, parts of the converted facilities are used as a training center and gas control and dispatch center.

    The Clayton Avenue office project was still in progress at the time of the field visit. It began as repair to old, leaking windows and evolved to a three-phase project redoing windows, carpeting, and layout, creating conference rooms and meeting rooms, and updating halls and restrooms.

    The Akron Call Center project expanded the office area of the facility to accommodate an increased number of agents from 43 to 180. Project work included a new generator, walls, restrooms, rooftop HVAC units, electrical, and furniture.

    All projects were performed with limited cost overruns. The Clayton Avenue project expanded as additional scope was identified, but the additional scope appeared reasonably identified. Considering the legitimacy of change orders, the projects came in within or near budgets.

    Blue Ridge had one note of concern with the Akron Call Center. Most cubicles in the expanded office space appeared to be personalized. In other words, it appeared that agents on different shifts did not share cubicles. If the facility operates multiple shifts, it may have been a cost-saving measure to share cubicles reducing the space needed in the project scope.

2. Compressor Stations and Equipment
    a. Field Visit 4 – Ludlow Station
    b. Field Visit 5 – Green (Stock) Station
    c. Field Visit 9 – Chippewa Station
    d. Field Visit 14 – Austintown Station

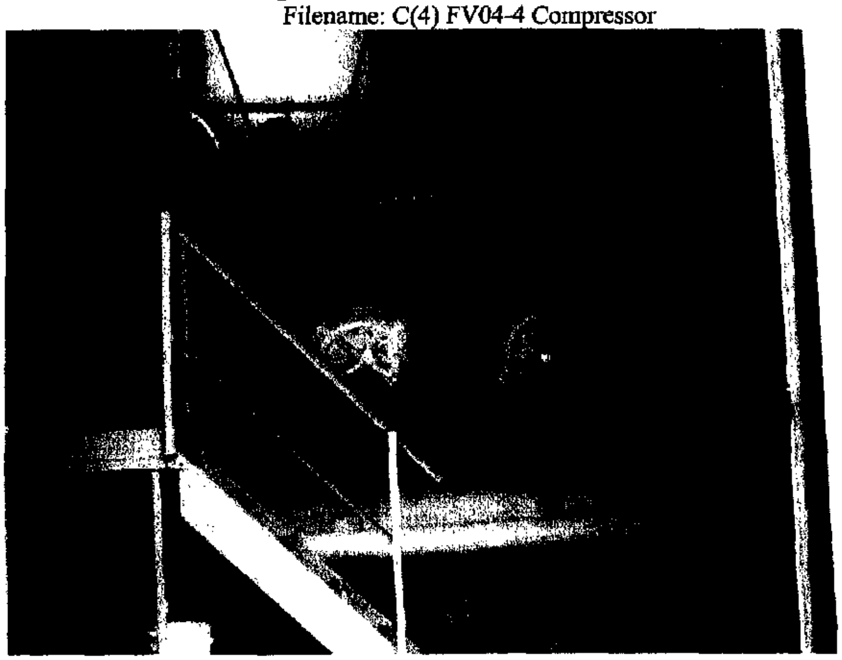
Blue Ridge visited four Compressor Station projects. The compressor units, housing, and controls appeared in good working order. Justification for these units ranged from update of old units to additional support in supplying distribution areas.

Part of the justification for additional compression was based on an agreement by Dominion with the Ohio Oil and Gas Association (OOGA) made in 2004. DEO agreed to put $13 million in the production system to increase the producer's ability to put more gas into DEO's system. By replacing the old unit with the new compressor at Ludlow, producers would pay DEO 20 cents per Mcf for the gas measured at the meter. Thus, the Ludlow compressor increased delivery, reliability, and revenue.

The Chippewa station added a compressor to increase compression capability and reliability. Some of the units at Chippewa are old (circa 1957) and not at peak performance.

The Green Station (called Stock at the site) is nearly complete. All physical structures and equipment appear reasonable.

Figure 14: Ludlow Station Compressor
Filename: C(4) FV04-4 Compressor

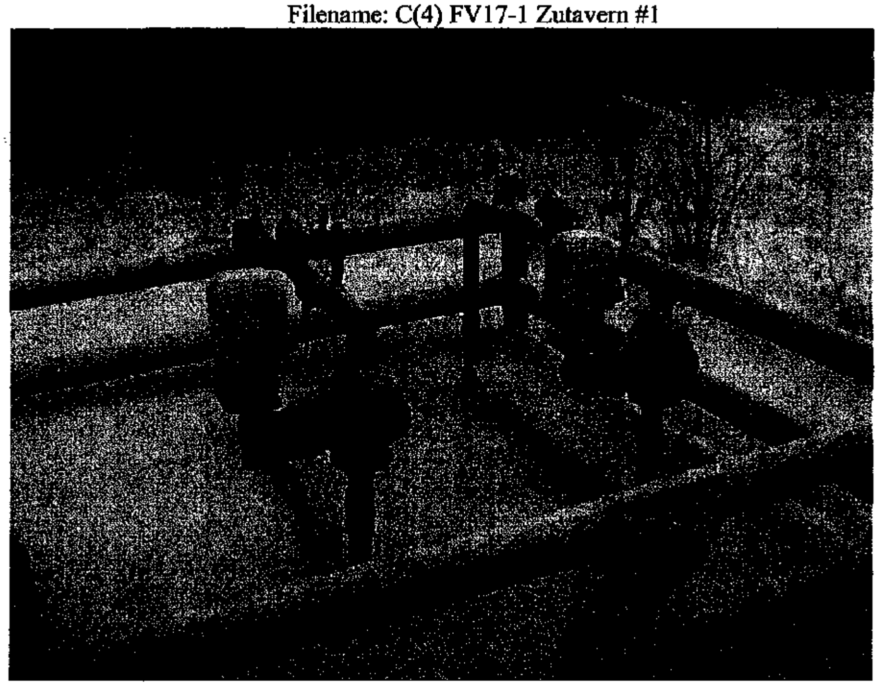


3. Measuring/Regulating Stations and Equipment
    a. Field Visit 13 – Wolf Station
    b. Field Visit 17 – NEO Asset Swap
    c. Field Visit 18 – Guernsey Station
    d. Field Visit 27 – Perry Station

The Wolf Station project was implemented to eliminate frequent alarms from the high pressure system. The Wolf Station is connected by three miles of piping from the Middlebranch Station. At Wolf, the line is split into inlets for downrate from the 99 lbs of pressure to a 60 lb and a 25 lb system. The project included gated access to prevent parking and turnarounds for both public and station safety. The project ran slightly over budget due to the unanticipated railway crossings.

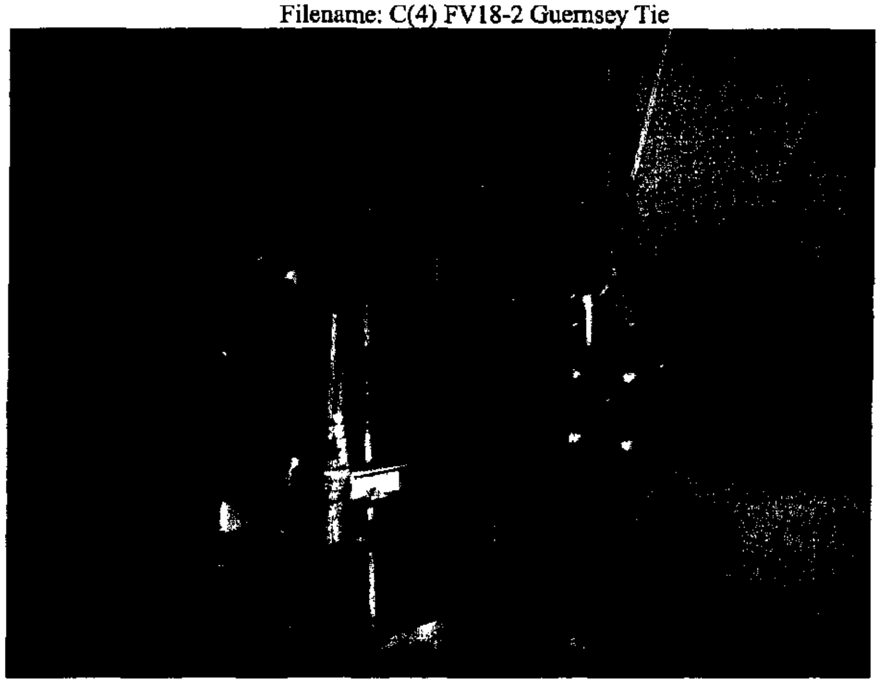
DEO initiated the Northeast Ohio Gas (NEO) asset swap project when it purchased a pipeline from Ohio Interstate Gas Transmission Company which branched off to both DEO and some NEO customers. DEO proposed a swap of those customers with others at various locations. Meters were installed at regulating stations that were already in place to read the gas going to these new NEO customers so that DEO could bill NEO. Eleven locations for meter installations were identified and completed. Blue Ridge visited two of these sites—the Zutavern Station and the Timber Ridge Station. No major problems were encountered during installation. Work was bid out to contractors. Each location was a one day or less job.

Figure 15: Zutavern Meter/Reg Station
Filename: C(4) FV17-1 Zutavern #1



The Guernsey Station was completed to tie in from a Tennessee Gas pipeline. Besides the associated piping, regulator, and valves, an odor pump and pump house were installed. No major problems occurred during the construction.

Figure 16: Guernsey Station
Filename: C(4) FV18-2 Guernsey Tie



4. Communication Equipment
    a. Field Visit 7 – Akron Call Center (Telecomm)

Besides renovating the Akron Call Center building (see Structures and Improvements above), the telecommunications equipment (switch) had to be upgraded for the expanded operational scope of the increased number of agents (43 to 180). Project work was conducted within schedule and budget.

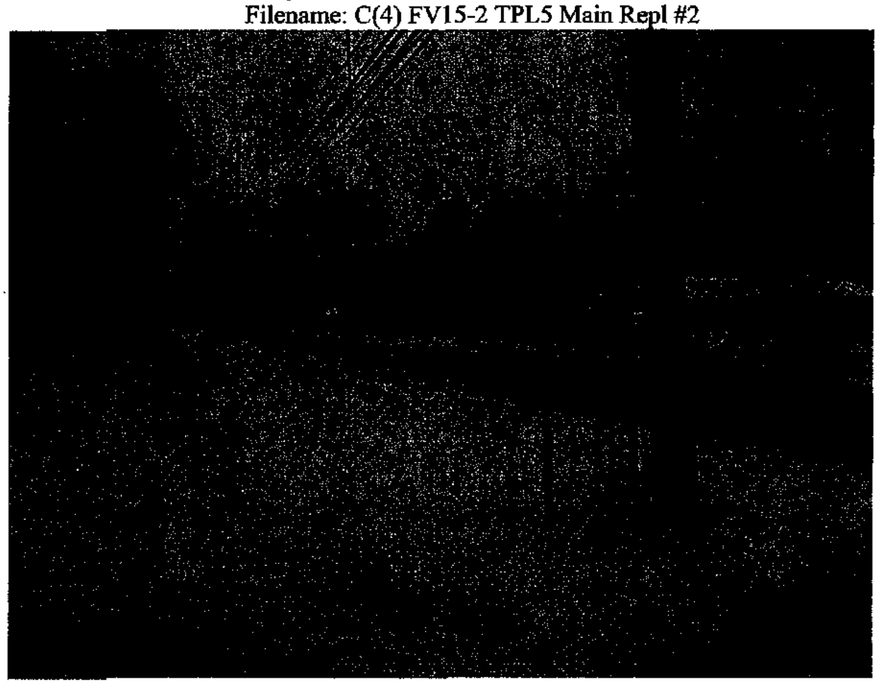
5. Mains
    a. Field Visit 8 – Breckville Rd
    b. Field Visit 12 – TPL5 Canton Airport
    c. Field Visit 15 – TPL5 2003
    d. Field Visit 16 – TPL5 2004
    e. Field Visit 28 – Mayfield Rd

The Breckville Road project was ongoing at the time of the field visit. The project entailed two phases with installation of about 3000 feet of 8 inch intermediate pressure pipe along the side of Breckville Road in each phase. The old 12 inch existing pipe, located in the median of the road, had several leaks requiring the replacement. The original scope had called for only the phase 1 work. However, because the crews were already in the area, they knew that the next 3000 feet would be required relatively soon, and they already had the pipe, the decision was made to implement phase 2. Blue Ridge's field visit coincided with the start of the phase 2 section. Blue Ridge observed reasonable construction practices with regard to activity, crew size, and safety concern.

Work on transmission pipeline number 5 (TPL#5) encompassed several projects. The Canton-Akron Airport project was necessary due to the airport's decision to extend a runway 700 feet over the existing pipeline. The pipeline had to be rerouted around the airstrip. No problems occurred in construction.

After a major effort in identifying leaks along the TPL#5, those areas in need of repair were grouped together based on risk. The riskier groupings were repaired first. Blue Ridge visited two of a higher risk grouping that was repaired in 2003 and another site of a less risky project grouping that was repaired in 2004. Although the projects were completed, some evidence of the repair was left at each site visited. Blue Ridge also examined project drawings and documentation.

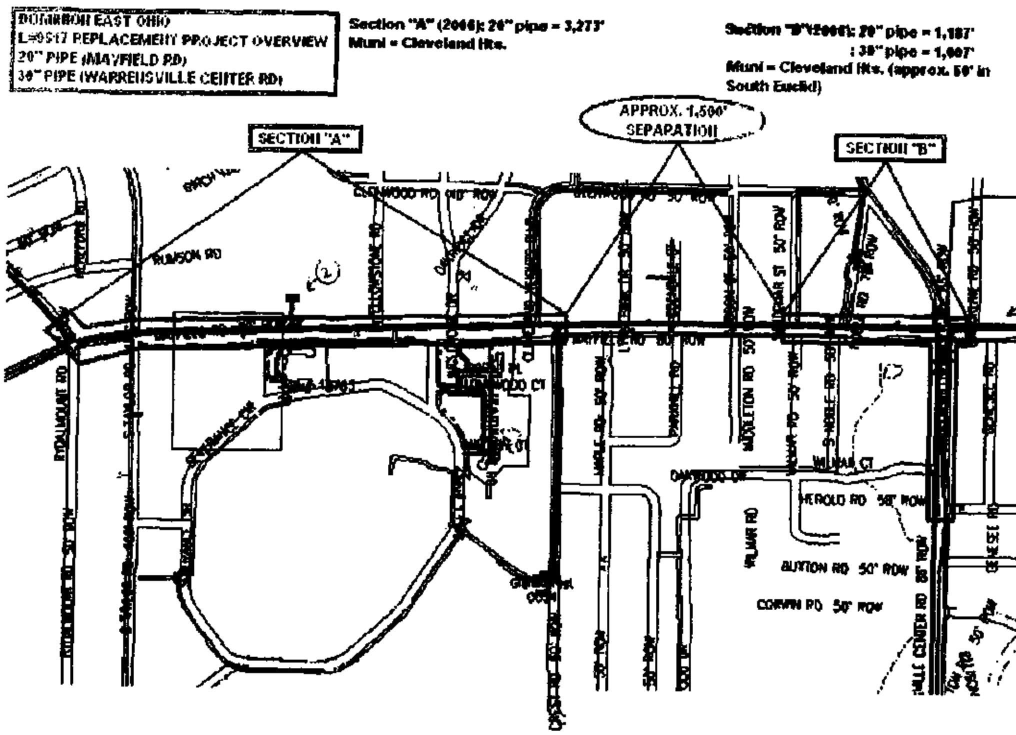
Figure 17: Site 1 - TPL#5 2003 Project
Filename: C(4) FV15-2 TPL5 Main Repl #2



The Mayfield Road included, in section A, the replacement of approximately 3,273 feet of 24 inch pipe within 26 inch casing along Mayfield Road with new 20 inch pipe. Section B had 1087 feet of pipe replaced. An additional 1007 feet of 26 inch pipe was replaced with 30 inch pipe. No major problems occurred during this project.

The drawing below shows a summary layout of the projects two sections (A and B) along Mayfield Road.

Figure 18: Layout of Mayfield Pipeline Replacement Project



6. Wells
    a. Field Visit 10 – Kormish Well
    b. Field Visit 11 – Corbin Well

Blue Ridge visited two production well projects both in various stages of installation. Both wells, 3900 feet deep, are strategically situated between two gas fields. After gas depletion, they are to be used as storage wells. The Kormish well is to be connected to the Corbin Well. The Kormish Well had been dug at the time of the field visit. Crews were about to begin installing the piping. The Corbin Well project was further along in process of pipeline installation. No problems had been encountered and none were anticipated.

7. Intangible-Software
   a. Field Visit 19-23 – Customer Care System
   b. Field Visit 24 – Manage Your Account - 2005
   c. Field Visit 25 – Manage Your Account - open
   d. Field Visit 26 – Minimum Service Standards

The Customer Care System (CCS) is a software package purchased by the Company and enhanced by Company programmers to replace their old system of customer information tracking. During Blue Ridge's field visit, a presentation of the CCS was made and major enhancements were highlighted. The project included major enhancements to service orders, meter reading, meter inventory, general system, billing, credit, and financial recording. Documentation of the enhancements and sample screens are included in Appendix 1. Five projects encompass the CCS upgrade. These five projects cover Software, Labor, Training/Education, Consultants, and Other Costs. The new system appears extremely comprehensive. Maneuverability within the system is also state-of-the-art. At first glance, the $46 million dollar cost of labor seems high, but the project lasted for several years and all projects were completed within the overall total budget of $62 million. The system does appear to be very useful. Company sponsors/users appeared proudly satisfied with the system.

The Manage Your Account project is a multi-year software development that provides customers online access to their account. Blue Ridge's field visit verified the development and implementation. Costs appear in line with the product.

The Minimum Service Standards project includes software enhancements to update the CCS system with regard to Ohio's minimum gas service standards. The changes were made to ensure compliance.

Findings

Blue Ridge found that all field visits verified the physical actuality of the project assets and that they appeared operational in used and useful activity. Although a rigorous audit of project costs was not a part of the current scope, minor concerns arose when comparing costs from project to project. The four compressor station projects and their costs are listed below.

Ludlow Station	Project #18922	$1,686,198.16
Green (Stock) Station	Project #30463	$4,154,623.95
Chippewa Station	Project #26055	$2,834,312.03
Austintown Station	Project #16326	$2,167,438.11

Although a rigorous audit of project costs was not a part of the current scope, Blue Ridge initially had a concern over the cost differential among the four compressor projects. However, it appears that the differences in amounts may be attributed to differences in the stations and differences in project scope (e.g., one vs. two compressors or necessity for additional building structure). From project documentation, it appears that reasonable control was exercised both during the project and, for those completed, at the end.

Other than the cost concern identified above, Blue Ridge believes project costs appear in line with project scope (original and contingency). Likewise, project controls for all projects seems adequate and reasonable.

Conclusions and Recommendations

Blue Ridge concludes that the analysis and findings of the projects visited provide adequate assurance that the scope, justification, and implementation of plant additions since the last rate case are reasonable and appropriately used and useful in operation.

Rate Base Task C.5

Task C.5 – The auditor selected shall review major additions, retirements, transfers, and adjustments to current date certain value of plant in service that have occurred since the date certain from the last rate proceeding.

Background

A utility's request for an increase in rates is many times precipitated by the increase in the investment in the assets that are used to serve the utility's customers. When the value of the assets in the rate base increases at a disproportionately faster pace than the utilities revenues, the utility's opportunity to earn its allowed rate of return decreases (everything else being equal). Besides the additional investment in plant, a number of other actions can affect the "net value" of the utility's rate base.

Besides additions to plant in service, a utility may have transfers of assets either in or out of rate base, retirements of assets that are no longer used and useful in serving customer needs, and other pro forma adjustments that could impact the value of the rate base. Thus, these items must be properly reflected in rate base so that the amount of revenues the Company could be authorized to collect in rates will permit the Company the opportunity to earn its allowed rate of return.

Blue Ridge reviewed DEO's major additions, retirements, transfers, and adjustments to its gas plant that have occurred since the date certain from the last rate proceeding in Docket 93-2006-GA-AIR to the current date certain value of plant-in-service. This task is related to Rate Base Task C.6 – Review annual plant balances and Rate Base Task C.8 – Plant Retirements and Depreciation.

Analysis

Major Additions

Blue Ridge's review of the Company's major additions since the last rate case was discussed in Tasks C.2, C.3 and C.4 above.

The following table summarizes the data provided by the Company in Schedule B2.3.

Table 19: Plant in Service Additions, Retirements, and Transfers (1997-2007)

Line	Classification	Additions	Retirements	Transfers	Total: Net Adds	Source:
1	Production	$ 18,873,447	$ 10,949,224	$ (4,129)	$ 7,920,094	Note 1
2	Storage**	$ 31,974,528	$ 5,142,796	$ (171,013)	$ 26,660,719	Note 1
3	Transportation	$ 48,455,950	$ 3,902,252	$ (2,085,266)	$ 42,468,432	Note 1
4	Distribution	$ 523,825,401	$ 60,602,769	$ 5,832,919	$ 469,055,552	Note 1
5	Genral	$ 115,649,686	$ 72,562,540	$ 323,939	$ 43,411,085	Note 1
6	Intangible	$ 48,794,060	$ 24,446,002	$ -	$ 24,348,058	Note 1
7	Total Plant (excluding Gas in Storage)	$ 787,573,072	$ 177,605,583	$ 3,896,451	$ 613,863,940	

Note 1: B-2.3 - Gross Plant Activity.xls/(Tabs:) Combined Prod - cells: line34, Combined Storage - cells: Line 37, Combined Trans - cells: Line 32, Combined Distr - cells: Line 47, Combined Genl - cells: Line 48, Combined Intang - cells: Line 23

Transfers

Blue Ridge initiated the investigation into transfers from accounts through a data request regarding transfers over $25,000.[197] In response, the Company identified transfers by year and by account. This information was then compared to the summary of transfers developed from Schedule B2.3 for reasonableness.[198] Blue Ridge found that the Company processed the transfers consistently and appropriately classified the costs in the various plant accounts. The auditor did note, however, that during the post East-West Ohio merger a significant amount of plant transferred within specific accounts reportedly for "Plant accounts reclassified due to conversion of multiple companies to one accounting system under one corporate umbrella."[199] The single largest item, valued at $280 million, related to transfers within two distribution sub-accounts and would have no impact on rate base determination. The value of the remaining transfers, and in particular recent years, does not present a concern at this time. The following table shows the plant transfers for the period 1997 through the date certain, March 31, 2007.

[197] Response to Data Requests BRCS-MTD-01-005.
[198] Workpaper *C5 – Plant transfers 98-07.xls.*
[199] Workpaper *C5 – Plant transfers 98-07.xls.*

Table 20: Plant Transfers 1997 through March 31, 2007

Line	Year (1)	Gas Ferc Account	Plant Transfers Description	Amount	Explanation
1	1997	3340	Field M&R Station Equip-Producing Gas-Other	1,467,249.95	Note 2
2	1997	3340	Field M&R Station Equip-Purchase Gas-Meters & Gauges	(417,257.36)	Note 2
3	1997	3340	Field M&R Station Equip-Purchase Gas-Other	(1,049,992.59)	Note 2
4	1997	3690	M & R Station Equipment-Meters & Gauges	979.79	Note 2
5	1997	3690	M & R Station Equipment-Other	(30,703.61)	Note 2
6	1997	3760	Low Pressure Mains	280,612,739.30	Note 2
7	1997	3760	Regulated Pressure Mains	(280,612,739.30)	Note 2
8	1997	3780	M & R Station Equipment (General)-Meters & Gauges	41,407.42	Note 2
9	1997	3780	M & R Station Equipment (General)-Other Equipment	(11,683.60)	Note 2
10	1997	3910	Office Furniture & Equipment - Equipment	5,482,924.57	Note 2
11	1997	3910	Office Furniture & Equipment - Furniture	(4,457,730.11)	Note 2
12	1997	3912	Office Furniture & Equipment - Computer Hardware	17,190,046.28	Note 2
13	1997	3920	Transportation Equipment - Light Trucks	695,824.25	Note 2
14	1997	3920	Transportation Equipment - NGV Kits NonLux Autos	129,552.49	Note 2
15	1997	3920	Transportation Equipment - NGV Kits Med Trucks<26k	34,094.64	Note 2
16	1997	3920	Transportation Equipment - Non Luxury Automobiles	(7,118.80)	Note 2
17	1997	3920	Transportation Equipment -Trailers (WV, OH & VA)	(91,262.82)	Note 2
18	1997	3920	Transportation Equipment - NGV Kits Light Trucks<10k	(163,647.33)	Note 2
19	1997	3920	Transportation Equipment - Heavy Trucks>13k	(695,824.25)	Note 2
20	1997	3940	Tools, Shop & Garage Equip - NGV Compression/Station	6,802,990.60	Note 2
21	1997	3940	Tools, Shop & Garage Equipment - Garage Equipment	(60,850.01)	Note 2
22	1997	3940	Tools, Shop & Garage Equip - Tools & Equipment	(6,742,140.59)	Note 2
23	1997	3960	Power Operated Equipment - Distrib. & Compression & Welding Equipment	122,680.18	Note 2
24	1997	3960	Power Operated Equipment - Other	(122,680.18)	Note 2
25	1997	3970	Communications Equipment - Radio	375,839.63	Note 2
26	1997	3970	Communications Equipment - Telephone System	63,235.90	Note 2
27	1997	3970	Communications Equipment - Communication Equipment	(18,654,316.27)	Note 2
28	1997	3980	Miscellaneous Equipment - Misc Equipment	98,381.62	Note 2
29	1997 Total			0.00	
30	1999	3320	Field Lines	(67,024.93)	Reclass production mains to distribution mains
31	1999	3760	Low Pressure Mains	196,465.25	Reclass production mains to distribution mains
32	1999	3760	Regulated Pressure Mains	(129,440.32)	Reclass production mains to distribution mains
33	1999 Total			-	
34	2000	3760	Low Pressure Mains	387,473.48	Reclass 105 distribution mains to 101 distribution mains
35	2000	3760	Regulated Pressure Mains	(115,099.85)	Reclass 105 distribution mains to 101 distribution mains
36	2000	3760	Distribution Mains-Future Use	(272,373.63)	Reclass 105 distribution mains to 101 distribution mains
37	2000 Total			-	
38	2003	3320	Field M&R Station Equip-Purchase Gas-Other	(142,087.42)	Reclass production mains between field M&R and distribution mains
39	2003	3340	Field M&R Station Equip-Purchase Gas-Other	2,248.20	Reclass production mains between field M&R and distribution mains
40	2003	3760	Regulated Pressure Mains	139,839.22	Reclass production mains between field M&R and distribution mains
41	2003	3960	Power Operated Equipment - Distrib. & Compression & Welding Equipment	117,327.38	Reclass welding equipment from other
42	2003	3960	Power Operated Equipment - Other	(117,327.38)	Reclass welding equipment from other
43	2003 Total			-	
44	2006	3670	Transmission Mains	(1,601,978.89)	Reclass transmission mains to distribution
45	2006	3690	M&R Station Equipment-Other	(38,208.02)	Reclass transmission M&R to distribution M&R
46	2006	3760	Regulated Pressure Mains	1,601,978.89	Reclass transmission mains to distribution
47	2006	3780	M & R Station Equipment (General)-Other Equipment	38,208.02	Reclass transmission M&R to distribution M&R
48	2006 Total			-	
49	2007	3690	M&R Station Equipment-Other	(144,507.22)	Reclass Franklin M&R from Trans. to Dist
50	2007	3690	M&R Station Equipment-Other	(309,512.06)	Reclass Shoop M&R from Trans. to Dist
51	2007	3780	M & R Station Equipment (General)-Other Equipment	309,512.06	Reclass Shoop M&R from Trans. to Dist
52	2007	3780	M & R Station Equipment (General)-Other Equipment	144,507.22	Reclass Franklin M&R from Trans. to Dist
53	2007 Total			-	
54	Grand Total			0.00	
55		Note:	(1) 1997 includes 1996 per the original source MTD 01-0-5		
56			(2) Plant accounts reclassified due to conversion of multiple companies to one accounting system under one corporate umbrella		
			(3) Source file MTD 01-05		

Retirements

Blue Ridge initiated the investigation into retirements from accounts through a data request which requested information regarding retirements recorded over $100,000 that were not associated with a construction project and work order that corresponded to sales of plant, which also generates retirements.[200]

The Company provided a detailed data response which showed the individual transaction data for the plant retirements for 1998 through the date certain March 31, 2007.[201] A review of this response showed that in 2006, the Company record 1,961 entries totaling $9.68 million of retirements, covering assets such as meters and equipment to distribution mains.[202] Similar numbers exist for prior years.

With respect to the timeliness of recording plant retirements, the normal time lags associated with recording of a work order[203] to the Company's plant accounting system

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[200] Response to Data Requests BRCS-MTD-01-007.
[201] Response to Data request BRCS MTD 06-03.
[202] Workpaper *C5 Plant Retirements MTD 06-03 SAP 2001-2007.xls.*
[203] The process of closing out a work order is referred to as "unitization."

and continuing property records should be considered. Blue Ridge investigated two aspects of this process.

The first part of the investigation included a review of the sample of work orders that Blue Ridge developed to test documentation requirement compliance. The auditor reviewed this documentation to determine the transaction date associated with the retirement in comparison to the in-service date of the assets added to plant.

The second part of the investigation was to focus on the Company's balance of plant that is categorized in FERC Account 106 – Completed Construction Not Classified (CCNC). The Company has, through the implementation of improved accounting controls, eliminated the use of FERC account 106, thereby eliminating a concern of accumulating retirements for significant periods.

Finally, the auditor noted the internal audit reviews conducted by the Company to comply with Sarbanes Oxley.

Findings

Blue Ridge's investigation indicates that DEO has reasonable procedures and controls to ensure that retirements are recorded based on the scope of the work orders. Blue Ridge determined that a majority of the retirements for work orders greater than $100,000 are associated with blanket purchase orders.[204]

Further, the Company has, through the implementation of improved accounting controls, eliminated the use of FERC account 106, thereby eliminating a concern of accumulating retirements for significant periods of time.

Finally, Blue Ridge noted that in the last three internal audits[205] of fixed assets conducted by the Company, there was an issue with [redacted].

The review of the project files shows that the in-service dates for the sample projects are readily displayed on the project documentation. A review of the sample projects showed that two projects[207] had retirements posted beyond the 60 days grace period past the in

[204] See Response to MTD 02-05.
[205] See CONFIDENTIAL Response to MTD 01-26 Fixed Assets SOX Audit Reports - 2004, 2005 and 2006. (note: each year contained in individual document).
[206] See CONFIDENTIAL Response to MTD 01-26 2004 Fixed Asset SOX Audit Report finding RN-136 & RN-138.
[207] See Projects 409076 and FCEOGCON – Workpaper *C3_MTD 01-06 CWOs GT 100K (SAP2001-2007).xls.*

service date. In both cases, the projects occurred prior to the SOX Internal Audit in 2004. Blue Ridge does note, however, that the review was [redacted] as posting date of the retirements for 1998 through 2000 was not provided.

Conclusion and Recommendation

Blue Ridge believes that the Company currently has adequate policies, procedures, and practices for recording of transfers and retirements. While the auditor could not determine whether retirements had been posted appropriately in the past, there is no resulting impact on rate base. With the elimination of the use of FERC Account 106 and the corrections made as a result of the two audits, Blue Ridge believes that the retirements and transfers reflected in the filing can be relied upon for setting rates.

Rate Base Task C.6

Task C.6-The auditor shall review annual plant balances, plant retirements, and their corresponding salvage and cost of removal.

Background

This task is closely associated with other tasks performed by Blue Ridge including General Requirements Task A.3 which verified the mathematical accuracy of the application; Rate Base Task C.1 which included a date certain balance sheet comparison to actual historical financial data; Rate Base Task C.2 which compared plant additions by year and by account; and Rate Base Task C.5 in which Blue Ridge reviewed major additions, retirements, transfers, and adjustments that occurred since the date certain from the last rate proceeding.

Analysis

Blue Ridge compared the 2006 year-end balances for Gas Plant in Service and Gas Stored Underground provided by the Company in its Supplemental Filing No. 18 to the 2006 Annual Report filed with the PUCO.[208]

Blue Ridge also compared the 2006-year end balances for Gas Plant in Service and Gas Stored Underground provided by the Company in its Supplemental Filing No. 18 to the 2006 Annual Report filed with the Ohio Department of Taxation.[209] Although significant differences exist between the amounts identified as additions and retirements, the ending balances are less than 2% different as shown in the following table.

[208] Workpaper *A(3)_Math.Accuracy Test.zip;* Folder *Workpapers;* Filename *Suppl #18 B-2.3 – Combined 1997-2007.xls.*
[209] Workpaper *C(6)_Plant Bal Comp Tax Rtn and Annual Report*, Spreadsheet *Comparison-Property Tax Rtn.*

Table 21: Comparison of 2006 Plant in Services Balances[210]

Description	Supplemental Schedule #18	Property Tax Return	Difference	% Difference
Beginning Balance	1,865,159,033	1,925,836,794	(60,677,761)	-3.25%
Additions	1,093,738,192	85,249,184	1,008,489,008	92.21%
Retirements	1,016,328,614	31,800,428	984,528,186	96.87%
Transfers	0	0		
Ending Balance	1,942,568,611	1,979,285,550	(36,716,939)	-1.89%

Blue Ridge also compared the combined 2006 depreciation reserve data from Supplemental Filing No. 21 to the Company's Annual Reports (FERC Form 2), page 29, Accumulated Provision for Depreciation-Account 108.[211]

In Task A.3, Blue Ridge also reviewed the Revenue Requirements Model provided by the Company and examined Schedule B-3.3 and Supplemental Filing No. 21, which provided annual summaries of activity affecting the depreciation reserve accounts. The information included accruals, salvage, retirements, cost of removal, and transfers.[212]

Using the details prepared for the Company Schedule B-2.3 and Schedule B-3.3 for periods ended December 31, 1996 to March 31, 2007, Blue Ridge compared the retirements from the Plant Balances to the Depreciation Reserve Balance. The difference between the two schedules was approximately 1 percent.[213]

Further comparisons were made to major retirements that were identified in Rate Base Task C.11 Plant Sales[214] to ensure that the retirements and salvage identified on these transactions were comparable to the net activity in Company Schedule B2.3.[215]

The Company stated that from 2001-2007 "there is no direct link in SAP between plant retirements in conjunction with construction projects." The Company stated it would provide information on selected projects.[216] Rate Base Task C.5 includes the review of the information provided on selected projects.

Findings

No findings or discrepancies were noted with respect to the recording of annual plant balances.

[210] Workpaper *C(6)_Plant Bal Comp Tax Rtn and Annual Report*, Spreadsheet *Comparison-Property Tax Rtn.*
[211] Workpaper *A(3)_Math.Accuracy Test.zip;* Folder *Workpapers;* Filename *Suppl #21 B-3.3 – Combined 1997-2007_Rev.xls.*
[212] Workpaper *A(3)_Math Accuracy Test.zip;* file *B-3 and B-3.1 Acct Depr by Acct.*
[213] Workpaper *C(6)_Comp Plant and Reserve Retire, Salvage, Removal.xls.*
[214] Workpaper *C(11) Plant Sales.xls* and response to Data Request BRCS MTD-01-08.
[215] Workpaper *C(6)_Comp Sales to Schedule B-2.3.xls.*
[216] Response to Data Request BRCS-MTD-01-006.

Rate Base Task C.7

Task C.7 – The auditor selected shall review current Commission approved amortization of reserve deficiency (if applicable).

Background

The depreciation reserve is the balance, according to the accounting records, for any plant account or group of accounts that reflects the portion of the cost of the plant in service, which has been recovered through depreciation. Conversely, the balance in the plant account minus the reserve represents the amount to be recovered in future accounting periods through a combination of depreciation expense, realized net salvage, and other debits and credits to the reserve.

The Company's current depreciation accrual rates became effective January 1, 2001, as approved by the Commission in Case No. 01-2592-GA-UNC, with the exception of the accrual rate for Account 303.03-Miscellaneous Intangible Plant, which became effective January 1, 2003 as approved by the Commission in Case No. 03-2204-GA-AAM.[217]

Analysis

The Company provided schedules prepared by Gannett Fleming that compared the book depreciation reserve and the calculated accrued depreciation. The reserve deficiency over-accrual is $105,400,192.[218] The Company explained that the average useful life of DEO's pipelines and other assets has been increasing, resulting in a buildup in the depreciation reserve over the years of approximately $105 million.[219]

The Company is proposing an adjustment to reflect total depreciation and amortization on date certain property at proposed depreciation rates, which are supported by the latest depreciation study performed by Gannett-Fleming.[220]

In prior rate cases, the Commission has reduced the Company's rate base by any over-accrued depreciation reserves to ensure that customers' rates properly reflect the depreciation expenses that they have historically paid in base rates.

In order to adjust its depreciation reserve to the proper amount, DEO proposes to reduce its future depreciation expenses over a ten-year period. DEO will use a corresponding amount to fund the deployment of automated meter reading (AMR) equipment throughout its system and increase its demand side management (DSM) expenditures to support customer conservation programs. The amortization of DEO's $105 million over-accrual over a decade will generate combined funding for AMR and DSM of approximately $10.5 million per year as shown in the following table.

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[217] Direct Testimony of Sylvia P. Green, p. 4, lines 14-20.
[218] DEO-3-2007-Dep-Table 2b provided on 3/3/08.
[219] Direct Testimony of Jeffrey A. Murphy, p. 29, lines 13-14.
[220] Direct Testimony of Vicki H. Friscic, p. 9, lines 4-6.

Table 22: Company's Proposal to Amortize Over-Accrued Depreciation Reserve[221]

Reserve Deficiency	$105,400,192
Amortized Reserve Deficiency though Depreciation Expense over ten-years	($10,540,020)
Funding for AMR Deployment Expense	$5,270,010
Funding for DSM Program Expense	$5,270,010

Findings

The Company recognizes that it is over accruing its depreciation reserve and proposes to reduce its future depreciation expenses over a ten-year period. DEO will use a corresponding amount to fund the deployment of AMR equipment throughout its system and increase its DSM expenditures to support customer conservation programs.

Conclusions and Recommendations

As part of its policy recommendations, Staff should consider whether it should adopt the Company's proposal to reduce its future depreciation expenses over a ten-year period and to use a corresponding amount to fund the deployment of AMR equipment throughout its system and increase its DSM expenditures to support customer conservation programs.

Rate Base Task C.8

Task C.8 - The auditor shall verify that plant retirements have been reflected in plant in service and depreciation reserve.

Background

When a utility adds replacement plant, the old plant that is being replaced will be retired from plant in service. Plant retirements generally do not have an effect on the Company's rate base because of the offsetting entries that are recorded in the plant in-service account and the corresponding reserve account. However, unrecorded retirements do have an impact on the Company's depreciation expense, and, therefore, have an impact on its revenue requirement request.

Analysis

The Company has procedures in place to recognize assets that are retired. The procedures for Fixed Asset Accounting state that assets that will be retired in the process of completing a project are entered into the database at the same time the new asset is added.[222] Procedures are in place for addition/replacement and retirement only projects that have in-service dates and actual quantity.[223]

[221] Schedule C-3.28 and DEO-3-2007-Dep-Table 2b provided on 3/3/08. See also Direct Testimony of Jeffrey A. Murphy, pp.29-32.
[222] Response to Data Request BRCS-MTD-01-030, attachment FA FORMS INSTRUCTIONS Sept 25 2007.doc.
[223] Response to Data Request BRCS-MTD-01-030, attachment Instructions for closing projects.doc.

The Company offered the following description of its process for estimating the amount of plant to be retired when the actual asset costs cannot be determined:

> If the retirement is for a piece or part of the whole unit and follows the Capitalization Policy and is a Unit of Property, determine the amount to retire by discounting the current cost to install the replacement equipment using the CPI Index to the original installation year
>
> The file used to determine the amount to retire contains the CPI rates taken from the U.S. Government Website and is updated yearly.
>
> If the calculated retirement amount is greater than the original cost, take the percent of the discounted retirement cost to the current cost and use that percent to retire the asset.[224]

The Company stated that it does not maintain a balance in Account 106-Completed Construction Not Classified.[225] The Company no longer uses Account 106. This account was eliminated with the implementation of SAP and the tightening of controls on reporting, as well as the use of WMIS.[226] Better reporting of in-service dates, system automation, and property unit information established upfront in the process essentially eliminates the need for Account 106.[227]

The Company also stated that it has very strict guidelines and reporting requirements for when retirements are posted. Retirements are posted in 10 days for in-service dates and 60 days for closure information.[228]

Findings

Verification that plant retirements have been reflected in plant and reserve accounts is encompassed in several of the tasks in Section C. Specific analysis was directed toward sampled work orders in Rate Base Task C.5.

Conclusions and Recommendations

The Company maintains reasonable controls and procedures relative to the posting of retirements. Requiring the recording of retirements at the time a new asset is recorded and eliminating Account 106 significantly limits the possibility of a backlog of unrecorded retirements.

[224] Response to Data Request BRCS-MTD-01-022, attachment MTD-01-022.doc.
[225] Response to Data Request BRCS-MTD-01-034.
[226] Work Management Information System.
[227] Green & White - Interview on 071219.
[228] Green & White - Interview on 071219.

Rate Base Task C.9

Task C.9-The auditor shall verify that amortization expense of capital leases corresponds with the capitalized amount and is amortized at the proper rate.

Background

For accounting and reporting purposes, two possible classifications exist for a lease: operating and capital. Circumstances surrounding the transaction determine the proper classification of a lease. According to the Statement of Financial Accounting Standards No. 13, *Accounting for Leases*, if substantially all of the benefits and risks of ownership have been transferred to the lessee, the lessee records the lease as a capital lease at its inception. Substantially all of the risks or benefits of ownership are deemed to have been transferred if any one of the following criteria is met:

1. The lease transfers ownership to the lessee by the end of the lease term.
2. The lease contains a bargain purchase option.
3. The lease term is equal to 75% or more of the estimated economic life of the leased property, and the beginning of the lease term does not fall within the last 25% of the total economic life of the leased property.
4. The present value (PV) of the minimum lease payment at the beginning of the lease term is 90% or more of the fair value to the lessor less any investment credit retained by the lessor. This requirement cannot be used if the lease's inception is in the last 25% of the useful economic life of the lease asset. The interest rate used to compute the PV is the incremental borrowing rate of the lessee unless the implicit rate is available and lower.

If at least one of the four criteria set forth above is not met, the lessee classifies a lease agreement as an operating lease.

Leasehold improvements represent capitalized improvements or additions to property that are leased from other parties. Leasehold improvements are usually considered intangible assets. Since investments in leasehold improvements are merely additions to the leased properties, these improvements are generally accorded rate base treatment in the same manner as any other plant in service. In this respect, the amortization of these improvements is an appropriate element of cost of service, while related accumulated amortization balances must be deducted from the rate base.

Analysis

The Company's lease transaction policy was reviewed. Leases are defined as operating or capital based on the Statement of Financial Accounting Standards No. 13, *Accounting for Leases*, and other pertinent accounting pronouncements. The Company's Fixed Asset Accounting group is responsible for recording initial value of a capital lease asset in its SAP financial software as the lesser of the fair market value of the property or the present value of future minimum lease payments. The initial lease liability equals the net present value of future minimum lease payments. The liability is split between the current and non-current portions. The current portion of the lease liability represents the principal portion of the lease payments that are scheduled to be made within the next 12 months for each lease. The reminder of the liability is classified as non-current. Capital leases are amortized in SAP using the straight-line method over either the estimated economic life of the property or the lease term. For each capital lease, an entry is recorded each month to adjust the current portion of the lease liability by adding back the interest portion of capital lease payments. The entry is based on the monthly interest expense amount from each capital lease amortization schedule.[229]

The Company provided the standard journal entries made into SAP for capital lease-related transactions.[230] The standard journal entries comply with the Company's policy.

The Company has included the following amounts as capital lease property in its rate base as of date certain:[231]

Description	Dollar Value
391.2 Property Held Under Capital Leases, Computer Hardware	$3,276,813.30
390 Structures & Improvements, Leasehold Improvements	107,799.76

The computer hardware included in Account 391.2 is comprised of 30 units of leased computer equipment. The equipment is being amortized using the straight-line basis over the term of the leases.[232] As of date certain, lease payments total $236,772.45 per quarter. Lease terms range from 36 to 48 months.[233]

According to the Supplemental Information included within this filing, the leasehold improvements were made to the Marietta Main Office on May 22, 2007. The lease payments as of March 31, 2007, total $2,450.00 per month for 48 months.[234]

Blue Ridge reviewed each unit for the proper recording of the dollar value of the plant investment in the accounting system. The amortization calculations and depreciation rates were also reviewed.[235]

Findings

The following comments and/or exceptions were noted:

[229] Response to Data Request BRCS-DHM-07-002, attachment DHM 07-02.doc.
[230] Response to Data Request BRCS-DHM-07-003, attachment DHM 07-03.doc.
[231] Supplemental Information No. 30 – Leased Property.
[232] Schedule WPB-3.4.
[233] Supplemental Information No. 30 – Leased Property.
[234] Supplemental Information No. 30 – Leased Property.
[235] Workpaper *C(9)_Capital Leases R-3 CONFIDENTIAL.xls.*

1. The Company's filings state that the Company leases computer equipment from ICON Funding.[236] The lease agreements provided indicate that some of the lessors are [redacted] and/or [redacted]. Subsequent lease agreements indicate that [redacted]. was formerly [redacted]. Subsequently, ICON U.S. Equipment became successor-in-interest to [redacted].

   RESULT: No impact to filing.

2. Quarterly rental payments, total rental amount due, and total interim rental on the lease agreements did not agree with the Company's Supplemental Information No. 30. The magnitude of difference is significant as illustrated in the following table.

Table 23: Comparison of Lease Agreement Amounts and Amounts Recorded in the Company's Filing Leased Computer Equipment[237]

	SOURCE:	Supplemental Information No. 30	Lease Agreement	Lease Agreement	Lease Agreement	Supplemental Info No. 30	Supplemental Info No. 30
	Identification or Reference No.	Description of Type and Use of Property	Quarterly Rental Payment	Total Rent Amount Due Initial Term	Total Interim Rental	Quarterly Lease Payment	Dollar Value of Plant Investment
1	5106147	Capital Lease PC's - Lease 66 - 2003	[redacted]	[redacted]	[redacted]	418.58	5,880.60
2	5106159	Capital Lease PC's Lease # 71	[redacted]	[redacted]	[redacted]	767.71	9,259.77
3	5106160	Capital Lease PC's Lease # 72	[redacted]	[redacted]	[redacted]	890.53	12,789.12
4	5106911	Capital Lease PC's - Lease # 76 2003	[redacted]	[redacted]	[redacted]	778.84	9,483.82
5	5106912	Capital Lease PC's - Lease # 77 2003	[redacted]	[redacted]	[redacted]	309.35	4,437.71
6	5107383	Capital lease # 90 - 2004	[redacted]	[redacted]	[redacted]	5,431.46	65,137.70
7	5107384	Capital lease # 91 - 2004	[redacted]	[redacted]	[redacted]	312.86	4,478.66
8	5108546	Capital Lease PC's - #126	[redacted]	[redacted]	[redacted]	5,356.72	63,521.97
9	5108547	Capital Lease PC's - #127	[redacted]	[redacted]	[redacted]	16,397.56	255,954.02
10	5108550	Capital Lease PC's - #97	[redacted]	[redacted]	[redacted]	4,483.63	52,041.38
11	5108551	Capital Lease PC's - #116	[redacted]	[redacted]	[redacted]	4,155.53	57,495.13
12	5112954	Capital lease # 133 - 2005	[redacted]	[redacted]	[redacted]	1,272.95	14,814.21
13	5112955	Capital lease # 134 - 2005	[redacted]	[redacted]	[redacted]	768.31	10,956.06
14	5118428	Capital Lease PC's - #165	[redacted]	[redacted]	[redacted]	1,692.54	19,574.26
15	5118429	Capital Lease PC's - #166	[redacted]	[redacted]	[redacted]	283.71	4,001.65
16	5118702	Capital Lease PC's - #176	[redacted]	[redacted]	[redacted]	1,015.00	11,713.64
17	5118703	Capital Lease PC's - #177	[redacted]	[redacted]	[redacted]	1,347.00	19,498.08
18	5119302	Capital Lease PC's # 183 - 2005	[redacted]	[redacted]	[redacted]	771.15	8,573.95
19	5119305	Capital Lease PC's # 184 - 2005	[redacted]	[redacted]	[redacted]	2,841.21	39,163.64
20	5119717	Capital Leased PC's - # 191	[redacted]	[redacted]	[redacted]	1,140.95	12,926.44
21	5119718	Capital Leased PC's - # 192	[redacted]	[redacted]	[redacted]	90,390.86	1,270,831.06
22	5119993	Capital Lease PC's - #196 - 2006	[redacted]	[redacted]	[redacted]	1,126.00	12,875.01
23	5119994	Capital Lease PC's - #197 - 2006	[redacted]	[redacted]	[redacted]	69,947.00	971,278.36
24	5119995	Capital Lease PC's - #198 - 2006	[redacted]	[redacted]	[redacted]	2,170.00	34,235.39
25	5120199	Capital Lease PC's - Lease 202 - 2006	[redacted]	[redacted]	[redacted]	971.00	11,143.55
26	5120200	Capital Lease PC's - Lease 203 - 2006	[redacted]	[redacted]	[redacted]	380.00	5,171.30
27	5120201	Capital Lease PC's - Lease 204 - 2006	[redacted]	[redacted]	[redacted]	638.00	9,969.33
28	5120532	Capital Lease # 206 - 2006	[redacted]	[redacted]	[redacted]	1,385.00	15,908.26
29	5120533	Capital Lease # 207- 2006	[redacted]	[redacted]	[redacted]	7,102.00	96,810.00
30	5120755	Capital Lease PC's - Lease # 211	[redacted]	[redacted]	[redacted]	12,227.00	166,889.53

[236] Supplemental Information No. 30 – Leased Property.
[237] Workpaper *C(9)_Capital Leases R-3 CONFIDENTIAL.xls.*

For example, Capital Lease PC's-Lease #71's lease agreement has a quarterly rental payment of [redacted], but the Company's amortization schedule and documents filed in connection with this proceeding show a quarterly payment of [redacted]. The total rental amount due is [redacted] for an asset with a dollar value of [redacted].

The Company explained that each quarter, Dominion Resources, Inc. (DRI) leases personal computers (PC) based on its business requirements. The leases are through a master lease agreement for all DRI companies. For each new PC master lease, Enterprise Asset management (EAM-part of DRI's IT group) assigns a portion of the master lease payment to each company that receives equipment from that lease. Using the example above for lease #71, the total quarterly lease payment is [redacted]. Of that amount, it was determined that the payment for the equipment assigned to DEO is [redacted]. The remainder of the [redacted] was assigned to other DRI companies based on the allocation of the PC equipment.[238]

RESULT: The auditor's concern is that documentation was not provided to support the values recorded in the Company's filing for leased computer equipment. Rate base may be over or understated depending on the allocation made by DRI's IT group for the equipment assigned to DEO.

3. The information provided for leases on or after October 1, 2005, included a "Lease Classification Analysis" which formally documents the operating vs. capital lease evaluation.
   RESULT: Good documentation of Company's policies and procedures.

4. Amortization schedules provided the depreciation expense until the Company changed its procedures. The information provided for leases on or after October 1, 2005, included a different format for the Capital Lease Amortization Schedule. The new schedule does not include a Depreciation Schedule. However, additional calculations from the information provided resulted in the conclusion that the annual depreciation expense calculated from the lease agreement and the stated dollar value of the asset agrees with the information in the Company's filing.
   RESULT: No impact to filing.

5. For several of the leases, the term of the leases provided within the filing is different from the supporting lease agreements. Supplemental Information No. 30 for Capital Lease PCs-Lease #211 shows a 60-month lease. The lease agreement is for [redacted]. The leasehold improvements had a similar difference. The lease agreement was for 60 months, but the Supplemental filing showed a lease term of [redacted].

[238] CONFIDENTIAL Response to Data Request BRCS-DHM-07-001 Follow Up.

RESULT: The difference between the terms of the leases could affect the calculation of the depreciation expense and accumulated depreciation. The actual dates from the lease agreements were used to determine the term of the lease and depreciation was recalculated as shown in item #7 below.

6. Several lease commencement dates from the lease agreements did not agree with the information filed in this proceeding.

Table 24: Different Start Dates between Lease Agreement and Filed Schedules[239]

Asset Description	Lease Agreement Commencement Date	Start Date per Supplemental Information No. 30
Capital Lease PC-Lease 66-2003	[redacted]	March 14, 2003
Capital Lease PC-#126		September 1, 2004
Capital Lease PC-#127		September 4, 2004
Capital Lease PC-#177		July 1, 2007
Leasehold Imprv-Electrical Service		May 22, 2007
Leasehold Imprv-Superstructure		May 22, 2007
Leasehold Imprv-Security System		May 22, 2007
Leasehold Imprv-Fence		May 22, 2007
Leasehold Imprv-Superstructure		May 22, 2007

IMPACT: The difference between the start dates could affect the calculation of the depreciation expense and accumulated depreciation. The actual dates from the lease agreements were used below to calculate the accumulated depreciation.

7. The auditor calculated accumulated depreciation based on the accumulated months from the start of the lease through date certain times the depreciation expense. The table below shows the difference between the accumulated depreciation calculated from the lease agreements and the amounts shown in the Company's filings. For each unit, the depreciation is calculated using the straight-line method over the term of the lease.

[239] Workpaper *C(9)_Capital Leases R-3 CONFIDENTIAL.xls.*

Table 25: Difference in Calculated Accumulated Depreciation and Filing Capital Leases Computer Equipment and Leasehold Improvements[240]

Supplemental Information No. 30 Description of Type and Use of Property	Lease Agreement Start Date	Lease Agreement End Date	Supplemental Info No. 30 Dollar Value of Plant Investment	Calculated From Lease Agree Lease Term Months	Calculated From Lease Agree Months of Accum Depr as of 3/31/2007	Calculated Dollar Value/ Term of Lease Annual Depreciation Expense	Calculated Accumulated Depreciation/ Amortization Reserve	WPB-3.4 Revised Accumulated Depreciation/ Amortization Reserve	Calculated Difference WPB-3.4 and Lease Agreement
Capital Lease PC's - Lease 66 - 2003	[redacted]		5,880.60	48	48	1,470.15	5,880.60	5,880.60	-
Capital Lease PC's Lease # 71			9,259.77	36	36	3,086.59	9,259.77	9,259.77	-
Capital Lease PC's Lease # 72			12,789.12	48	46	3,197.28	12,158.55	11,993.12	165.43
Capital Lease PC's - Lease # 76 2003			9,483.82	36	35	3,161.27	9,483.82	9,483.82	-
Capital Lease PC's - Lease # 77 2003			4,437.71	48	43	1,109.43	3,935.39	3,884.71	50.68
Capital lease # 90 - 2004			65,137.70	36	36	21,712.57	65,137.70	65,137:70	-
Capital lease # 91 - 2004			4,478.66	48	35	1,119.67	3,402.54	3,359.66	42.88
Capital Lease PC's - #126			63,521.97	36	30	21,173.99	53,581.96	52,935.97	645.99
Capital Lease PC's - #127			255,954.02	48	30	83,988.51	161,926.47	159,974.02	1,952.45
Capital Lease PC's - #97			52,041.38	36	33	17,347.13	48,331.02	47,707.38	623.64
Capital Lease PC's - #116			57,495.13	48	33	14,373.78	40,046.96	39,529.13	517.83
Capital lease # 133 - 2005			14,814.21	36	27	4,938.07	11,234.11	11,113.21	120.90
Capital lease # 134 - 2005			10,956.06	48	27	2,739.02	6,231.26	6,165.06	66.20
Capital Lease PC's - #165			19,574.26	36	24	6,524.75	13,212.63	13,051.26	161.37
Capital Lease PC's - #166			4,001.65	48	24	1,000.41	2,025.84	2,002.65	23.19
Capital Lease PC's - #176			11,713.64	36	21	3,904.55	6,919.72	6,834.64	85.08
Capital Lease PC's - #177			19,496.08	48	21	4,874.52	8,638.73	8,532.08	106.65
Capital Lease PC's # 183 - 2005			8,573.95	36	18	2,857.98	4,334.61	4,287.95	46.66
Capital Lease PC's # 184 - 2005			39,163.64	48	18	9,790.91	14,849.55	14,686.64	162.91
Capital Leased PC's - # 191			12,926.44	36	15	4,308.81	5,433.89	5,387.44	46.45
Capital Leased PC's - # 192			1,270,831.06	48	15	317,707.77	400,664.79	397,135.06	3,529.73
Capital Lease PC's - #196 - 2006			12,875.01	36	12	4,291.67	4,339.36	4,292.01	47.35
Capital Lease PC's - #197 - 2006			971,278.36	48	12	242,819.59	245,517.59	242,820.36	2,697.23
Capital Lease PC's - #198 - 2006			34,235.39	60	12	6,847.08	6,923.16	6,848.39	74.77
Capital Lease PC's - Lease 202 - 2006			11,143.65	36	9	3,714.52	2,816.84	2,786.55	30.29
Capital Lease PC's - Lease 203 - 2006			5,171.30	48	9	1,292.83	980.39	971.30	9.09
Capital Lease PC's - Lease 204 - 2006			9,969.33	60	9	1,993.87	1,512.02	1,496.33	15.69
Capital Lease # 206 - 2006			15,908.26	36	6	5,302.75	2,866.11	2,852.26	13.85
Capital Lease # 207- 2006			96,810.00	48	6	24,202.50	12,168.48	12,102.00	66.48
Capital Lease PC's - Lease # 211			166,889.53	48	3	41,722.38	10,314.70	10,430.53	(115.83)
: 3912 - Property Held Under Capital Leases, Comp. Hdw.			3,276,813.60			842,574.33	1,173,928.52	1,162,741.60	11,186.92
ELECTRICAL SERVICE	[redacted]		36,463.28	60	10	7,296.66	6,141.35	**	Calculated in total
SUPERSTRUCTURE			4,131.12	60	10	826.22	895.41	**	Calculated in total
SECURITY SYSTEM			8,732.21	60	10	1,746.44	1,469.92	**	Calculated in total
FENCE			19,130.44	60	10	3,826.09	3,220.29	**	Calculated in total
SUPERSTRUCTURE			39,322.71	60	10	7,864.54	6,519.32	**	Calculated in total
. 390-Structures & Improvements-Leasehold Improvements			107,799.76			21,559.95	18,146.29	17,821.00	325.29
:ed Leases			3,384,613.36			864,134.28	1,192,074.81	1,180,562.60	11,512.21

***Total from Schedule B-3*

RESULT: It appears that the Company has understated its Accumulated Depreciation for its capitalized leases by $11,512.21. Therefore, the Company's rate base may be overstated.

Conclusions and Recommendations

The Company maintains reasonable controls and procedures relative to the categorization of lease agreements as operating or capitalized leases. They have established a "Lease Classification Analysis" which formally documents the operating vs. capital lease evaluation.

Several exceptions were identified between the Company's filing and the supporting documentation. PC leases are handled through a company-wide master lease. The Company did not supply documentation that supports the value of the capitalized PCs it carries on DEO books. Rate base may be over or understated depending on the allocation made by DRI's IT group for the equipment assigned to DEO.

Differences exist between the Company's filing and the lease agreements related to the term of the leases. The result is that the Company has understated Accumulated

[240] Workpaper *C(9)_Capital Leases R-3 CONFIDENTIAL.xls.*

Depreciation for its capitalized leases by $11,512.21. Therefore, the Company's rate base may be overstated by an immaterial amount.

Rate Base Task C.10

Task C.10 – The auditor shall analyze Allowance for Funds used During Construction (AFUDC), or Interest Used during Construction (IDC) to ensure a proper calculation.

Background

The public utility industry uses the allowance for funds used during construction (AFUDC or AFDC) to expressly impute a return to equity during the production period of property being produced, including that imputed return in income (for financial accounting purposes only) and then capitalizing it into the basis of the property being produced or Construction Work in Progress (CWIP). The Uniform System of Accounts provides specific instructions on how to calculate and record AFUDC for those utilities that are governed by FERC. Most state commissions have adopted this methodology.

Analysis

The Company's policy states that Allowance for Funds Used during Construction (AFUDC) has been defined as a component of construction costs representing net cost of borrowed funds and a reasonable rate on other funds used during the period of construction. AFUDC is capitalized until the project is placed in operation by concurrent credits to the income statement and charges to utility plant based generally on the amount expended to date on the particular project.[241]

No monetary limitation or threshold exists for computing AFUDC. All qualifying projects (with certain exceptions listed below) are charged with AFUDC regardless of the estimated cost/amount of the project. Qualifying projects also includes intangible projects, such as the development of major computer software. Exclusions from the interest calculation include:

1. Land and land rights
2. Construction Work in Progress (CWIP) dollars that are closed at the end of each month – examples include massed general and massed distribution projects, since charges to these accounts are settled monthly to plant in service
3. Deferred or other work in progress[242]

The formula for computation of the rate used to compute the allowance is that which is contained in the Gas Plant Instruction 3 of the FERC Uniform System of Accounts, as described in Order 561. The accounting for the allowances computed will be that which is prescribed in FERC Accounts 419.1 Allowance for Other Funds Used During

[241] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.
[242] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.

Construction and 432 Allowance for Borrowed Funds Used During Construction-Credit.[243]

The Company follows the following rules for the application of rates:

1. On all projects, except those excluded above, allowance for funds shall be computed and recorded beginning with the month after the settlement of charges from the qualifying project to the AUC (Asset Under Construction – CWIP). The cost basis to be used in computing allowances for funds will be the beginning of the month balances of projects in construction work in progress (subject to exclusions above).
2. Allowances for funds will cease with the month during which the project or part thereof is placed in service or is available for service. At this time Fixed Asset Accounting will be notified to change the User Status to Status 40 (Complete No AFC). This will prevent the future calculation of AFUDC.
3. There will be a compounding effect on allowances for funds. In other words, an AFUDC rate will be applied to construction charges and previously charged AFUDC on the project.
4. No interest will be charged and posted to a WBS element if the computed AFUDC amount is under $10.
5. There will be no final true up or retroactive adjustment to the estimated rate applied throughout the year.
6. There will be no AFUDC accrual on a capital project in the case of a management decision to delay (suspend) the work activity of a project.[244]

The following additional information is provided within the Company's policies on AFUDC regarding the calculation of AFUDC Rate:

- The Fixed Asset Department will perform the calculation of the AFUDC rate.
- Treasury and Cash Management will provide cost of borrowed funds and the capital structure.
- The Virginia Power Delivery and Generation rates are adjusted as a result of Virginia allowing CWIP in the rate base. (Virginia Power Energy (Electric Transmission) is subject of FERC authority to regulate rates and FERC does not include CWIP in rate base.)
- The Fixed Asset Department will be responsible for loading the rates into the Project Systems module of SAP.
- A revised rate will be calculated quarterly based on updated information.
- Separate rates will be calculated for Virginia Power and Consolidated Natural Gas.
- Effective January 1, 1977, FERC amended the Uniform System of Accounts establishing formulas for maximum allowable AFUDC rates.[245]

[243] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.
[244] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.

The Company provided its calculation by the FERC Order No. 561 method in its Supplemental Information No. 27 and updated the computation for the fourth quarter 2007 in response to a data request.[246]

The analysis conducted by Blue Ridge consisted of testing the calculation of the AFUDC in several periods covered by the Company's filing to substantiate the monthly rate of the debt and equity components. Supporting documentation from the Company included guidelines referenced above, schedules of common equity balances, and the long-term debt and short-term debt rate and amounts.[247]

The Company has not included Construction Work in Progress (CWIP) in its rate filing as seen on Schedule B-1 and the supporting Schedule B-4. Therefore, the Company did not include within this filing a schedule showing the distribution of construction expenditures as of date certain which would have included AFUDC.

Schedule D-5 shows a test year balance in AFDC of $392,290 with a percent of Earnings Available for Common Equity of 4.88%.[248] This amount was reconciled to the Company's income statement in General Requirements Task A.3.

The Company provided a schedule listing the applied AFUDC rates by month for 2001 through the fourth quarter 2007.[249] The rates varied from a low of 1.150% (2nd Quarter 2004) to a high of 7.050% (1st Quarter 2001).

Testing of the AFUDC calculation was conducted by mathematically verifying the amount of AFUDC applied to individual work orders that were selected as samples in Task C.3. The amount of AFUDC applied as compared to the total project cost was reviewed for reasonableness. In addition, the AFUDC entry date was reviewed for consistency with the in-service dates of the work order (noting reversals if appropriate). The review also included verification that AFUDC was not charged if the work order was not subject to AFUDC.[250]

Findings

The results of the AFUDC calculations on the sampled work orders resulted in the following findings:

[245] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.
[246] Supplemental Information No. 27 and Response to Data Request BRCS-MTD-01-014, attachment 2007 DEO Rate Case AFUDC Sep 2007.xls.
[247] Supplemental Information No. 27 and Responses to Data Requests BRCS-MTD-01-014 and MTD-01-015.
[248] Schedule D-5, page 2 of 3.
[249] Response to Data Request BRCS-MTD-01-015.
[250] Workpaper *C(10)_AFUDC from Sampled Projects.xls.*

1. Project #400429 – The project is described as the Original CAMP Software now known as Customer Care System (CCS). The project was comprised of a number of different components that were posted between February 1998 and December 2000. The AFUDC charged to each component ranged from 4.8% to 9.13% of the component total cost. Although AFUDC rates were not provided prior to 2001, the percent of AFUDC to total cost may be higher than would have been allowed. However, for the total project, AFUDC was only 5.51% (shown in the following table), which appears reasonable.

Table 26: Project 400429 AFUDC to Project Costs[251]

	Project	Project Asset Name / WO Title	Earliest Post Date	Latest Post Date	In-Service Date	Project Cost	AFUDC Posted	% AFUDC Posted to Total Project Cost
1	400429	30848-303000-610-01000	2/28/1998	12/31/2000	12/31/1999	46,033,299.17	2,208,346.80	4.80%
2	400429	30848-303000-610-02000	2/28/1998	12/28/2000	12/31/1999	3,085,283.99	281,711.42	9.13%
3	400429	30848-303000-610-03000	2/28/1998	12/23/2000	12/31/1999	316,180.11	8,472.51	2.68%
4	400429	30848-303000-610-04000	2/28/1998	4/17/2000	12/31/1999	10,873,333.32	785,776.26	7.23%
5	400429	30848-303000-610-05000	2/28/1998	12/31/1999	12/31/1999	1,588,229.16	124,015.91	7.81%
						61,896,325.75	3,408,322.90	5.51%

2. The Company's policy states that AFUDC will cease with the month during which the project or part thereof is placed in service or is available for service.[252] A review of the 42 sample work orders found 12 instances where AFUDC was applied after the in-service dates as shown in the following table. A total of $157,514.47 is recommended to be reversed from these projects, thereby reducing the project costs and plant in service.

Table 27: AFUDC Applied after In-Service Dates from Sample Work Orders[253]

Line No.	Project	PROJ ASSET NAME / WO TITLE	Location Description	FERC	Total Project Cost	AFUDC Amount	In-Service Date	AFUDC After In-Service
1	400382	2-605-21462-00273	Easement for Pipeling 10004921	365	159,395.22	7,145.22	11/12/1996	(7,145.22)
2	400466	2/1/01 CONVERSION	SAMS Software System	303	449,545.43	91,469.83	1/1/2001	(91,469.83)
3	411611	EOG SAP LICENSE FEES	SAP Licenses	303	1,021,328.72	37,817.72	1/1/2001	(37,817.72)
4	OHGENCS	akron call center capital	Akron Call Center TeleUpgrade	397	1,175,733.19	38,405.55	12/31/2001	(8,498.72)
5	9631	STRUCTURES & BUILDINGS	Akron/Eastwood (60000004)	375	1,721,428.28	5,508.74	2/28/2002	(1,977.40)
6	12231	M&R STATION EQUIPMENT	Twinsburg M&R Station	369	651,489.42	394.72	10/24/2002	(394.49)
7	410129	Reloc. Brookpark Rd.	Dist M/L on Brookpark Rd	376	1,261,151.45	16,597.06	5/17/2002	(1,687.35)
8	16326	STRUCTURES & BUILDINGS	Austintown Station Bldg	327	158,064.06	431.57	12/30/2003	(367.60)
9	21198	BUILDINGS-WAREHOUSE CHIPPEWA	Chippewa Station Warehouse	351	133,290.09	2,538.23	7/8/2005	(907.08)
10	21675	BUILDING- SECURITY SYSTEM BRUSH	Brush M&R Station	366	173,157.91	1,459.50	3/31/2005	(684.29)
11	1W06701255	STEELYARD COMMONS 0 JENNINGS R44109	Steelyard Commons Reg Station	378	710,325.37	74.35	11/27/2006	(27.65)
12	28148	COMPRESSION EQUIPMENT	Clay Compressor Station	333	1,365,059.88	12,417.09	1/17/2007	(8,639.14)
		Total AFUDC after In-Service Dates from Sample Work Orders						(157,514.47)

3. Project 400382-This project is described as a right of way/easement. In addition to having AFUDC posted after the in-service date shown above, this type of project is specifically excluded from AFUDC per the Company's policies. The Company policy excludes AFUDC interest calculation for land and land rights.
4. Project 400466-This project is described as Strategic Automated Mapping System geographic representation of pipelines. In addition to having AFUDC posted after

[251] Workpaper *C(10)_AFUDC from Sampled Projects.xls.*
[252] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.
[253] Workpaper *C(10)_AFUDC from Sampled Projects.xls.*

the in-service date, the amount of AFUDC posted was 20.35% of the total project costs. A recommendation to reverse AFUDC totaling $91,469.83 is included in the analysis above because the AFUDC was applied after the in-service date. However, the Company should research how such a high rate of AFUDC was applied to this project.

5. Project 2A05789753-This project is described as the "replace 15,000 of 20" pipe TPL5 North 2004." The in-service date was not available in the documentation provided. Based on a review of the dates for the various cost components, it appears that AFUDC was not accrued after the final cost posting of 12/31/04.

Conclusions and Recommendations

Blue Ridge found that the Company's AFUDC policy and processes for calculating the debt and equity components of AFUDC are reasonable.

A review of the AFUDC applied to sampled work orders identified several areas that the Company should investigate. The Company's policy states that AFUDC will cease with the month during which the project or part thereof is placed in service or is available for service.[254] A review of the 42 sample work orders found 12 instances in which AFUDC was applied after the in-service dates. A total of $157,514.47 is recommended to be reversed from these projects, thereby reducing the project costs and plant in service.

One project had AFUDC in excess of 20% of the total project costs applied after the in-service date. The total dollars are included in the $157,514.47 discussed above. The Company should investigate how such a high rate of AFUDC was applied to this project.

Rate Base Task C.11

Task C.11 – Any major sale of plant or equipment since the Applicant's last base rate case shall be reviewed to determine if gains or losses from the sale are treated properly.

Background

Gains and/or losses on the sale of plant assets that are a part of rate base must be appropriately assigned to accounts so that the impact to ratepayers is fairly applied.

Analysis

In response to a data request, the Company provided asset sales for the period since the last rate case in 1993.[255] Journal entry documentation was included in the Company's data request response. The following chart presents asset sales since 1997 by project/workorder number.

[254] Response to Data Request BRCS-MTD-01-012, attachment MTD 01-12 2006.doc.
[255] Response to Data Request BRCS-MTD-01-008.

Table 28: Plant Sales[256]

Year	Project/ Workorder no.	Project Description	Plant Retired Amount	Gain/Loss
2002	12571	02MAR-sale of 99900002 and D0071,D0194	164,332.13	118,211.31
2002	14423	02NCA-10005583-SOLD M&R STA#4529-14423	93.37	-
2004	17580	03NCA-2003 SALE TO PRODUCERS #3	89,211.20	-
2004	19340	04NCA-15001801 ABANDON WELL 1801LN3264-sell well	16,905.27	-
2005	20416	PRODUCTION LINES AND M&R'S TO BE SOLD TO PRODUCER	253,698.05	-
2005	23082	05NCA-SALE OF PRODUCTION LINES 23082	77,907.96	-
2005	23699	05NCA-10002242-SELL TANK & SEP-23699	6,817.62	-
2005	23701	05NCA-10001267-SELL WELL LINES-23701	1,647.70	-
2006	29704	06NCA-10004316-SELL M&R/INST GTS-29704	527.17	-
2006	30829	06NCA-10004198 PROD REQ TAP-F958-30829	1,427.43	-
1998	400483	048814-EOG-Youngs/Wa	2,731.43	-
1998	400486	049999- Conversion D	8,561.08	-
2000	402539	049999- Conversion D	75,256.80	268,501.00
1998	404231	BLK98-Vehicles & Work Equip	827,022.54	-
2000	406129	BLK-1999 MTR SET COMM PY	105.29	-
1999	406184	BLK-1999 PURCH VEHICLES	865,380.34	-
2000	409026	Sale of old Ashtabula Shop	12,848.40	47,556.95
2000	409076	BLK-2000 PURCHASE VEHICLES	565,109.65	-
2002-5	409170	00NCA SALE 5 TO PRODUCERS	1,603,350.75	-
2000	409223	8400-Retire Dist Land	838.51	7,500.00
2001	411347	01LIM-001- 215 WEST MARKET STREET SALE	353,558.50	354,311.74
2002-6	DEOPROPSALES	DEO PROPERTY SALES	182,169.18	61,449.04
2001-7	O7100	DEO Transportation Equipment	5,353,952.14	-
2002	O7400	DEO OTHER TOOLS AND WORK EQUIPMENT	106,350.65	-
2002	O9700	01NCA METER SALES 3	73,551.45	-

For all sales, the accounting entries debit the reserve accounts of accumulated depreciation and credit the appropriate plant accounts.

Table 29: Assignment of Plant Sales[257]

Reserve Accounts Accum Depr	Plant Accounts	Description
1331021	1311020	Intangible
1331030	1311030	Land Easements
1331040	1311040	Buildings
1331050	1311050	Gen, Prod, & Gathrg Plant
1331052	1311052	Underground Storage Plant
1331060	1311060	Transmission
1331070	1311070	Distribution
1331080	1311080	Transportation
1331090	1311090	General Plant & Equipment

[256] Workpaper *C(11) Plant Sales.xls*, tab-*Sum Project.*
[257] Workpaper *C(11) Plant Sales.xls*, tab-*Accounts.*

The Company calculates gain or loss only on the sale of land. The sales proceeds settle as a credit to the salvage account on the project and are booked to the 1331800 Accumulated Depreciation – Salvage Reserve Account.

Table 30: Sample Accounting Entries on Sale Gain/Loss[258]

Project #	1311030	1311050	1319999	1331050	Gain 6105030	Loss 6205020
411347	-162,552.00		147,500.15			-15,051.85
	-28,309.33		397,672.12			369,362.79
						354,310.94
DEOPROPSALES	-2,938.51		64,464.79			61,526.28
	77.24					-77.24
		-631.61		631.61		0.00
						61,449.04
12571	-4,000.00		101,702.32		97,702.32	
	-838.85		21,347.84		20,508.99	
					118,211.31	

The Company presented only one transaction prior to 1998. In 1995, a sale of a number of wells was made to Belden and Blake. In that transaction, a gain of $60,530.52 was realized and assigned to FERC account 421.11-Gain on Disposition of Property.

Findings

Blue Ridge found that the transactions indicate a reasonable assignment of the proceeds to the various accounts.

Conclusions and Recommendations

Blue Ridge concludes that the reasonable assignment of the proceeds to the various accounts results in a proper presentation of the effect on net rate base.

Rate Base Task C.12

Task C.12- The auditor shall verify the Applicant's inventory of Material and Supplies (M&S) included in the application is for repair or replacement of existing plant and equipment and not for construction projects.

Background

Material and Supplies used in conjunction with the operation of the business may be included in rate base if the amount on hand is reasonable for efficient and economical operation. The Company has included $2,278,708[259] of plant and operating material and supplies in its filing. This amount is based on a 13-month average and excludes construction-related materials and supplies (which in DEO's case is zero).[260] As

[258] Workpaper *C(11) Plant Sales.xls*, tab *Sum Project*.
[259] Schedule B5.1, Col 3, Line 7.
[260] Schedule B5.1, Col 3, Line 6.

discussed with Staff, it was decided that the low dollar amount of inventory (0.2% of rate base totaling $1,071.9 million) and the fact that the requested amount is $99,841 less than the date certain amount,[261] negated any significant investigation or analysis.

However, since the determination of significance is dependent on the amount of M&S on hand, field visits to Company storerooms is an appropriate means to provide reasonable assurance of amounts included in rate base calculations.

Analysis

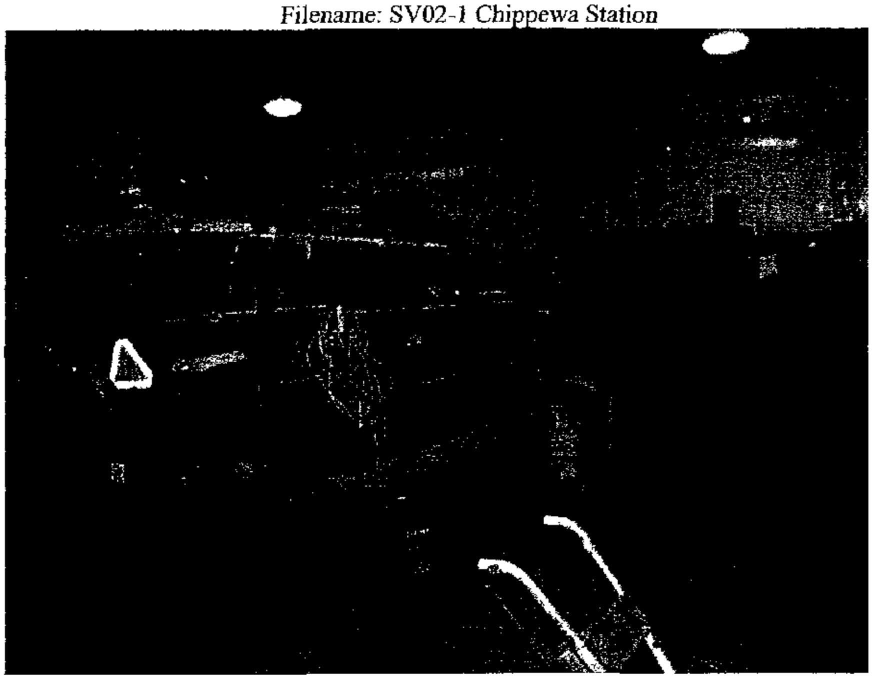
Blue Ridge conducted field visits to three Company storerooms: Randall, Chippewa, and Canton.[262] All three locations appeared to have adequate security. Supplies were contained within fenced/walled areas. Although no standard manual of procedures was at the storeroom offices, specific procedures for withdrawal and replenishment of supplies were discussed and appropriate forms in evidence. Supply Chain Services provides training in procedures every two years. The frequent onsite visits of Supply Chain Services personnel also provide necessary oversight of methods and standards.

Emergency stock of pipe less than 12 inches is kept at both Randall and Canton. Emergency stock of greater than 12 inches is found only at Randall.

Through last year, obsolete inventory had been on a schedule at each station to be reviewed approximately every two years. From 2008 on, a cycle system is being initiated so that all inventories are checked every year. Randall conducted an inventory evaluation in 2005, Chippewa in 2006, and Canton in 2007. Adjustments were minimal ($12,000 or less).

[261] Schedule B5.1, Col 6, Line 7 minus Schedule B5.1, Col 3, Line 7.
[262] Workpapers *C(12) Storeroom Visit List.xls* and *C(12) Storeroom Visits.doc*.

Figure 19: Chippewa Station Storeroom
Filename: SV02-1 Chippewa Station



Findings

Blue Ridge found that storeroom material and supplies appeared to be reasonable and adequate with regard to amount, procedure, security, training, and control.

Conclusions and Recommendations

Blue Ridge concludes that it is reasonable to consider reliable the Rate Base test year data for material and supplies.

Rate Base Task C.13

Task C.13-The auditor shall become familiar with any regulatory assets, the nature of the entries, dollar amounts, reasons for deferrals, and whether regulatory approval has primarily been obtained for the deferrals.

Background

A regulatory asset is created when a company capitalizes all or part of an incurred cost that would otherwise be charged to expense when it is probable that future revenue at least equal to the capitalized costs will result from the ratemaking process and that future revenue will be provided to permit recovery of the previously incurred costs. Blue Ridge requested the Company provide a list of any regulatory assets or regulatory liabilities in connection with the rate proceeding.

Analysis

The Company's trial balance as of date certain (March 31, 2007) shows the following balances for regulatory assets and liabilities:[263]

Table 31: Regulatory Assets and Liability on March 31, 2007, Trial Balance[264]

The East Ohio Company
Regulatory Assets and Liability Natural Balances
As of March 31, 2007

Account	Description	Balance
1242134	Reg Asset-Ppd Pension-Accum Amort Of F	(24,357,689.20)
1242135	Reg Asset-Ppd Pension-Increm OPEB Cost	34,828,480.78
1242143	Reg Asset-Work Force Reduct-Special Te	3,049,596.01
1242160	Reg Asset-Energy Choice Related Expens	(13,965,241.86)
1242199	Reg Asset-Bad Debt Expense	22,813,102.71
1242200	Reg Asset-Bad Debt Tracker	42,902,022.35
1242201	Reg Asset-Bad Debt Tracker- Estimated	(1,005,515.00)
1292915	Weatherization - Energy Efficiency	2,830,869.45
	Total Regulatory Assets	67,095,625.24
2220030	Regulatory Liability SE FAS 158	(12,423,753.00)
2220260	Regulatory Liability - Cost of Removal	(78,567,920.98)
2220261	Regulatory Liability - Asset Retiremen	(6,469,673.37)
2220270	Regulatory Liability - Order 636 Trans	(2,048,925.34)
	Total Regulatory Liabilities	(99,510,272.69)
	Total Regulatory Assets and Liabilities	(32,414,647.45)

The Company is requesting to amortize the highlighted items in this proceeding.

Account number 2200260-Regulatory Liability - Cost of Removal totaling ($78,567,921) was included in Schedule B-3 but was adjusted out of the jurisdictional balance included in this proceeding. The Company's explanation for the adjustment was to eliminate the regulatory liability for cost of removal associated with non-legal obligations, which is included in FERC account 108.[265] The Company further explained that "at the direction of Commission Staff, DEO recorded a rate case adjustment to eliminate the effect of accounting for asset retirement obligations for ratemaking purposes."[266]

The FERC Account trial balance as of date certain showed the following balances:[267]

[263] Supplemental Information 40b Trial Balance Jan-Mar 2007 Natural.
[264] Workpaper *C(13)_Regulatory Asset & Liability FERC-Natural TB.xls.*
[265] Schedule B-3.1, Page 2 or 5. Description and Purpose of Adjustment Line 6.
[266] Response to Data Request OCC-75b, obtained by Blue Ridge through Data Request BRCS-WF-01-001.
[267] Supplemental Information 40d Trail Balance Jan-Mar 2007 FERC.

Table 32: FERC Account Balances Regulatory Assets and Liabilities[268]
The East Ohio Company
Regulatory Assets and Liability FERC Balances
As of March 31, 2007

Account	Description	Ending Balance
9182300	Other Regulatory Assets	64,264,755.79
9254000	Other Regulatory Liabilities	(20,942,351.71)
		43,322,404.08

The following is a reconciliation of the natural account balances and the FERC account balances for Regulatory Assets and Liabilities. Natural account 1292915 was not included within the account map provided.[269] The amount in SAP (natural) account 2220260 was included as a component of FERC account 9108000-Accumulated Depreciation-Utility Plant.

Table 33: Reconciliation of Natural Account Balances and FERC Account Balances Regulatory Asset and Liabilities[270]

The East Ohio Company
Reconciliation of Regulatory Assets and Liability Natural Balances and FERC Balances
As of March 31, 2007

Account	Description	Balance	Mapping	Mapped Natural	FERC Balance	Difference
1242134	Reg Asset-Ppd Pension-Accum Amort Of F	(24,357,689.20)	9182300	(24,357,689.20)		
1242135	Reg Asset-Ppd Pension-Increm OPEB Cost	34,828,480.78	9182300	34,828,480.78		
1242143	Reg Asset-Work Force Reduct-Special Te	3,049,596.01	9182300	3,049,596.01		
1242160	Reg Asset-Energy Choice Related Expens	(13,965,241.86)	9182300	(13,965,241.86)		
1242199	Reg Asset-Bad Debt Expense	22,813,102.71	9182300	22,813,102.71		
1242200	Reg Asset-Bad Debt Tracker	42,902,022.35	9182300	42,902,022.35		
1242201	Reg Asset-Bad Debt Tracker- Estimated	(1,005,515.00)	9182300	(1,005,515.00)		
1292915	Weatherization - Energy Efficiency	2,830,869.45	Not on Map	-		
	Total Regulatory Assets	67,095,625.24	**9182300**	**64,264,755.79**	**64,264,755.79**	**-**
2220030	Regulatory Liability SE FAS 158	(12,423,753.00)	9254000	(12,423,753.00)		
2220260	Regulatory Liability - Cost of Removal	(78,567,920.98)	9108000	-		
2220261	Regulatory Liability - Asset Retiremen	(6,469,673.37)	9254000	(6,469,673.37)		
2220270	Regulatory Liability - Order 636 Trans	(2,048,925.34)	9254000	(2,048,925.34)		
	Total Regulatory Liabilities	(99,510,272.69)	**9254000**	**(20,942,351.71)**	**(20,942,351.71)**	**-**
	Total Regulatory Assets and Liabilities	(32,414,647.45)				

The Company stated that it did not pursue Commission authorization to defer the regulatory asset and liability balances that it is seeking to amortize in this rate case.[271]

The Company is seeking to amortize the following regulatory assets and liabilities in this proceeding:

- Workforce Reduction Curtailment Loss – FAS 106 curtailment loss in connection with 1995 nonunion work force reduction in the amount of $5,213,000 recorded

[268] Workpaper *C(13)_Regulatory Asset & Liability FERC-Natural TB.xls.*
[269] Account map was provided in the response to Data Request BRCS-WF-03-002, attachment WF 03-032_FERC Direct Map Table.xls.
[270] Workpaper *C(13)_Regulatory Asset & Liability FERC-Natural TB.xls.*
[271] Response to Data Request BRCS-DHM-01-002.

in Oct-1995. The portion of this loss representing the acceleration of the FAS 106 transition obligation ($3,253,000) is being amortized to expense over 206 months commencing Nov-1995. The balance of the loss ($1,960,000) was deferred for DEO's next base rate case.[272]

This amount is included in general ledger number 1242143 – Reg Asset-Work Force Reduct-Special Term Benefits.[273] The difference of $1,089,596 between the natural trial balance as of March 31, 2007,[274] and the Company workpaper WPC-3.9 supporting the rate case is the balance that is currently being amortized at $15,791 per month over 206 months.

Table 34: Difference between Trial Balance and Company's Filing Workforce Curtailment

The East Ohio Company
Work Force Reduction - Difference between Trial Balance and Rate Case Schedules
As of March 31, 2007

Account	Description	Balance
1242143	Amount per Natural Trial Balance	3,049,596.01
1242143	Amount per WPC-3.9	1,960,000.00
	Difference	1,089,596.01

The Company is requesting the following adjustment:[275]

Total Unamortized Curtailment Loss	$1,960,000
Amortization Period	3
Total Adjustment	$653,333
Jurisdictional Allocation Percentage	100%
Jurisdictional Amount	$653,333

The Company offered the following explanation for the Workforce Reduction Curtailment Loss it is seeking to recovery.

> "In late 1995, The East Ohio Gas Company recorded a curtailment loss resulting from a nonunion early retirement program implemented in 1995 to effect a workforce reduction. The total curtailment loss of $5.2 million was comprised of two components. The first component consisted of $3.253 million of additional expense related to the pre-1993 FAS 106 transition obligation equivalent to the FAS 106 transition obligation that East Ohio was permitted in its last rate case, Case No. 93-2006-GA-AIR, to

[272] WPC-3.9-11 RegAssets 3-31-07.
[273] WPC-3.9-11 RegAssets 3-31-07 and Supplemental Information No. 31.
[274] Supplemental Filing #40b Trial Bal Jan-Mar 2007 Natural.
[275] Schedule C-3.9.

amortize over 20 years. Accordingly, the $3.253 million recorded in October 1995 was amortized commencing November 1, 1995, for the remainder of the allowed 20-year amortization period. The second component, $1.960 million, represents the additional expense in the period from adoption of FAS 106 in 1993 through recognition of the early retirement impact in 1995 brought about by the fact that retired employees would be drawing down the post-retirement benefits sooner than was anticipated in the original actuarial studies that established the initial FAS 106 periodic expense. DEO chose to defer that additional prior period expense similar to a transition obligation in anticipation of seeking recovery in its next rate case, and has reflected this amount in the adjustment shown in Schedule C-3.9."[276]

- Unrecovered Weatherization Costs (WPC-3.10) – to amortize into test year operating expenses the balance of deferred weatherization and associated carrying costs remaining at the end of the amortization period authorized in DEO's previous rate case (Case No. 93-2006-GA-AIR).[277]

Included in general ledger number 1292915--Weatherization Energy Efficiency.[278]

The Company is requesting the following adjustment:[279]

Remaining Balance after Amortization of Balance Allowed in Last Rate Case:	
Weatherization Total Deferred (unamortized balance)	165,986
Weatherization Interest Deferred Post Rate Case	2,406,777
Weatherization Interest	258,106
Total Unrecovered Weatherization Costs	$2,830,869
Amortization Period	3
Total Adjustment	$943,623
Jurisdictional Allocation Percentage	100%
Jurisdictional Amount	$943,623

The Company explained:

"In DEO's last rate case, the Commission approved a Stipulation and Recommendation that was generally based on the Staff Report of Investigation. The Staff Report included an adjustment for recovery of certain deferred weatherization expenses and associated carrying charges. The adjustment shown in Schedule C-

[276] Response to Data Request BRCS-DHM-01-002.
[277] Schedule C-3.10.
[278] WPC-3.9-11 RegAssets 3-31-07 and Supplemental Information No. 31.
[279] Schedule C-3.9 and WPC-3.9-11 RegAssets 3-31-07.

> 3.10 reflects weatherization expenses deferred in excess of the amount that was amortized and the carrying charges associated with that amortization."[280]

- Over-Recovered Order 636 Transition Costs (WPC-3.11) – to amortize into test year operating expenses the balance of over-recovered Order 636 transition costs allocated to "old" transport customer plus accumulated interest.[281]

Included in General Ledger Number 2220270 – Regulatory Liability-Other 636 Transition Costs.[282]

The Company is requesting the following adjustment:[283]

Total Over-recovered Transition Costs	$(2,048,925)
Amortization Period	3
Total Adjustment	$(682,975)
Jurisdictional Allocation Percentage	100%
Jurisdictional Amount	$(682,975)

The Company explained:

> "In Case No. 94-164-GA-UNC, the Commission approved a Stipulation and Recommendation that specified the manner in which gas supply restructuring ("GSR") costs incurred as a result of FERC Order 636 would be allocated to sales and transportation customers. The costs allocated to sales customers were trued-up through the GCR mechanism. Due to GSR refunds received from interstate pipelines after DEO ceased collecting the costs from transportation customers, the Company over-recovered costs from the transportation class. The credit to expense reflected in Schedule C-3.11 reflects DEO's proposal to credit those costs and the associated interest in base rates over three years."[284]

The amounts requested by the Company to amortize these regulatory assets and liabilities included in Schedule 3.9, 3.10, and 3.11 and supported by the Company's workpapers WPC-3.9, WPC-3.10, and WPC-3.11 were traced to their source documentation in section Operating Income Task B.13 of this report.

If the Company had included these regulatory assets and liabilities in rate base, the rate base balance would have increased by $2,741,944 as follows:

280 Response to Data Request BRCS-DHM-01-002.
281 Schedule C-3.11 and WPC-3.9-11 RegAssets 3-31-07.
282 WPC-3.9-11 RegAssets 3-31-07 and Supplemental Information No. 31.
283 Schedule C-3.9.
284 Response to Data Request BRCS-DHM-01-002.

Workforce Reduction Curtailment Loss Asset	$1,960,000
Unrecovered Weatherization Costs Asset	$2,830,869
Over-Recovered Order 636 Transition Costs Liability	($2,048,925)
Total Regulatory Assets and Liabilities	$2,741,944

Findings

The Company is seeking to include the following amortized costs associated with regulatory assets and liabilities in this proceeding.

Workforce Reduction Curtailment Loss	$653,333
Unrecovered Weatherization Costs	$943,623
Over-Recovered Order 636 Transition Costs	$(682,975)
Total Amortized Regulatory Assets and Liabilities	$913,981

The Company provided explanations for each of the items for which it is seeking recovery. The amounts requested were traced to their source documentation in Task B.13 in Section B. Operating Income of this report.

The Company did not pursue Commission authorization to defer the regulatory asset and liability balances that it is seeking to amortize in this rate case.[285]

Conclusions and Recommendations

The Company has not included the regulatory asset and liability balance in rate base but is requesting to amortize costs for Workforce Reduction, Unrecovered Weatherization Costs, and Over-Recovered Order 636 Transition Costs as adjustments to its revenue requirements. As part of its policy recommendations, Staff should consider the Company's proposal to amortize these regulatory asset and liability balances.

Rate Base Task C.14

Task C.14-The auditor shall investigate the accounting for income taxes and verify that the Applicant has properly accounted for the differences on the balance sheet.

Background

Deferred income taxes are amounts reflected on the Company's books that represent the income tax effect caused by expenses being recognized in different years for income tax purposes than for regulatory or financial reporting purposes. An example would be a Company's use of straight-line depreciation for ratemaking purposes and accelerated depreciation for income tax purposes. Straight-line depreciation is commonly used for regulatory accounting and ratemaking purposes, whereas companies commonly use accelerated depreciation for calculating federal income taxes.

[285] Response to Data Request BRCS-DHM-01-002.

The use of an IRS accelerated depreciation rate for computing the tax and a company-adopted straight-line depreciation method for computing operating costs under generally accepted accounting principles (GAAP) will reduce the income tax bill for the utility in the early life of the property and create a timing difference in the form of a deferred tax credit. But timing differences usually reverse, increasing the tax bill in later years and eliminating the amount created with the timing difference by amortizing the deferred credit balance to zero at the end of the service life of the property.

This and similar types of differences are referred to as book/tax timing differences or deferred income taxes. Beyond depreciation book/tax timing differences, a number of other instances can exist when some items of income and/or expense are properly included in the book income of one period but on the income tax return for a different period.

Analysis

The Company's filing Schedule B-1 included a line item for Other Rate Base items which included Adjusted Jurisdictional totals of $17,349 for Investment Tax Credits and $172,677,194 for Deferred Income Taxes for a total of $172,694,543 This amount reduces the rate base component in this proceeding. Company Schedule B-6 provided a list of the items that comprise the Other Rate Base items. The Company provided supporting documentation from its SAP/FERC reporting as of March 31, 2007, for the balances.[286]

[286] Response to Data Request BRCS-GPR-1-024.

Table 35: Deferred Income Taxes
Comparison of Schedule B-6 to SAP/FERC Accounts[287]
The East Ohio Company d/b/a Dominion East Ohio
Case No. 07-829-GA-AIR

Deferred Income Taxes-Comparing Schedule B-6 to SAP/FERC Accounting
As of March 31, 2007

Line No.	Account No.	Description	Schedule B-6 Total (A)	Schedule B-6 Adjustment (B)	Schedule B-6 Adjusted Jurisdiction (C)	GPR 1-24 FERC (D)	GPR 1-24 SAP (E)
1	190	UPGA	14,834,002	(14,834,002)	-	14,834,002	
2	283	Alternative Minimum Tax	(6,725,694)	6,725,694	-		
3	283	Bad Debts	3,150,347	-	3,150,347		
4	283	Bad Debts - PIPP	44,293,192	(44,293,192)	-		
5	283	Bad Debts - Tracker	6,158,474	(6,158,474)	-		
6	283	Benefits	(15,250,994)	-	(15,250,994)		
7	283	FIN 48 Bad Debts	(2,576,592)	2,576,592	-		
8	283	FIN 48 Bad Debts - PIPP	(20,277,702)	20,277,702	-		
9	283	FIN 48 Bad Debts - Tracker	(10,372,892)	10,372,892	-		
10	283	Inventory	(5,610,092)	-	(5,610,092)		
11	282	ITC	(893,966)	-	(893,966)		
12	283	Pension	220,235,229	(220,235,229)	-		
13.	283	Taxes	634,577	-	634,577		
14	282/283	Depreciation	190,692,828	-	190,692,828		
15	282/283	Other	(45,506)	-	(45,506)		
			403,411,209	(230,734,015)	172,677,194		
16	9282000	GPR 01-24 FERC DIT-Other				192,102,936	
17	9283000	GPR 01-24 FERC DIT-Other				211,364,635	
18		Deferred Income Tax-current					44,354,275
19		Deferred Income Tax-other					373,947,298
20		**Total Deferred Income Taxes**	**418,245,211**	**(245,568,017)**	**172,677,194**	**418,301,573**	**418,301,573**
21		Difference Total Schedule B-6 and GPR 1-24				(56,362)	

The difference of $56,362 between the FERC/SAP balances the amount in Schedule B-6 represents the state deferred income taxes. State income taxes current and deferred, are not part of cost of service.[288]

The Company provided the following explanations to Other Rate Base items shown in the table above.[289]

> Line 1 – FERC Account 190 UPGA (Unrecovered Purchased Gas Adjustment). An adjustment of ($14,834,002) was made resulting in a zero balance that eliminates the accumulated UPGA deferred taxes. UPGA is recovered through a separate rider and not through base rates.
>
> Line 2 – FERC Account 283 Alternate Minimum Tax. An adjustment of $6,725,694 was made resulting in a zero balance that eliminates the accumulated

[287] Workpaper *C(14)_Deferred Income Taxes.xls.*
[288] Response to Data Request BRCS DHM-02-002.
[289] Response to Data Requests BRCS-DHM-01-003 and BRCS-DHM-02-003.

deferred taxes impact associated with the Alternative Minimum Tax Credit. The Company computes the current federal income tax expense for ratemaking purposes using the regular tax rate of 35% and not the minimum tax rate of 20%, as reflected in the consolidated federal income tax return.

Line 3 – FERC Account 283 Bad Debts. This account reflects the bad debt reserve changes.[290]

Line 4 – FERC Account 283 Bad Debts PIPP. An adjustment of ($44,293.192) was made resulting in a zero balance that eliminates the accumulated PIPP deferred taxes. PIPP bad debts are recovered through a separate rider and not through base rates.

Line 5 – FERC Account 283 Bad Debts Tracker. An adjustment of ($6,158,474) was made resulting in a zero balance that eliminates the accumulated deferred taxes associated with the uncollectibles expense adjustment mechanism. Most of the Company's non-PIPP uncollectible expense is recovered through a separate rider and not through base rates.[291]

Line 6 – FERC Account 283 Benefits. The Company's explanation consisted of a list of the following items: severance payout, vacation accruals, health and welfare benefits, FAS 112 long-term disability, FAS 106 OPEB, RSA's timing, short-term incentive plan, FAS 112 Workers Compensation.

Line 7, 8, and 9 – FERC Account 283 FIN 48 Bad Debts. Adjustments of $2,576,592, $20,277,702, and $10,372,892 were made to these three accounts resulting in zero balances. These adjustments eliminates the impact on accumulated deferred taxes resulting from the Company's adoption of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, effective January 1, 2007. Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, FASB Interpretation No. 48 establishes standard for measurement and recognition in financial statements of positions taken by an entity in its income tax return. Positions take, or expected to be taken, by an entity in its income tax return that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taking authorities with full knowledge of all relevant information. In the case of these adjustments, due to the uncertainty about the timing of certain deductions for tax purposes, the application of FASB Interpretation No. 48 resulted in a decrease to the Company's accumulated deferred tax liabilities.

[290] Response to Data Request BRCS-DHM-02-003 referring to WPF-2.1&2.1A May 2009.xls in Supplemental Filing Workpapers.
[291] Response to Data Request BRCS-DHM-02-003 referring to WPF-2.1&2.1A May 2009.xls in Supplemental Filing Workpapers.

Line 10 – FERC Account 283 Inventory. The Company's explanation consisted of a list of the following items: capitalized inventory-IRC 263A, book/tax inventory pricing differential, Stark Summit Migration adjustment, Line Pack inventory adjustment.[292]

Line 11 – FERC Account 283 ITC. The Company explained that this amount is the Investment Tax Credit.[293]

Line 12 FERC Account 283 Pension eliminates the accumulated pension deferred taxes. The FAS 87 impact of accounting for pensions is eliminated for this base rate filing.[294]

Line 13 – FERC Account 283 Taxes. The Company's explanation consisted of a list of the following items: OH Gross Receipts Taxes, OH Mcf Excise Taxes, property tax adjustment-PY, state income tax deferred (fed Effect), state income tax deferred-current.[295]

Line 14 – FERC Accounts 282/283 Depreciation. This item is comprised of the following: capitalized interest IRC 263A, self constructed property 263A (unclassified labor), capitalized overheads (78-80, 81-86), amortization of computer software, software development, Int Dev WS-purchased/SW Exp (books), AFUDC current year equity, AFUDC current year debt, contribution in aid of construction, book depreciation, capitalized overheads (1978-1980), capitalized overheads (1981-1986), tax depreciation, Fin 48 depreciation, balance sheet analysis adjs/rounding, clearing account depreciation, bonus depreciation, FAS 143-ARO, book amortization of capital lease, tax depreciation-capital leases, CONAG, sale of leased equipment, book gain on disposition of assets, tax gain on disposition of assets, dismantling costs, IRC 179 clean fuel property, Idaho Power adjustment.[296]

Line 15 – FERC Accounts 282/283 Other. This item consists of the following: delay rental costs, charitable contributions limitations, IRS interest adjustment, directors charitable contributions, weatherization adjustment, CDF Partnership write-down, partnership income (miscellaneous), insurance, injuries & damages reserve, other reserves (restructuring), restructuring accruals-paid out, other reserve accruals, Energy Choice Program, Weatherization Program.[297]

[292] Response to Data Request BRCS-DHM-02-003 referring to WPF-2.1&2.1A May 2009.xls in Supplemental Filing Workpapers.
[293] Response to Data Request BRCS-DHM-02-003 referring to WPF-2.1&2.1A May 2009.xls in Supplemental Filing Workpapers.
[294] Direct Testimony of Robert D. Taylor on behalf of Dominion East Ohio, DEO Exhibit 4.0, pp. 4-5, lines 1-23 and 1-10.
[295] Response to Data Request BRCS-DHM-02-003 referring to WPF-2.1&2.1A May 2009.xls in Supplemental Filing Workpapers.
[296] Response to Data Request BRCS-DHM-01-004, attachment B-6 Support Schedule.xls.
[297] Response to Data Request BRCS-DHM-01-004, attachment B-6 Support Schedule.xls.

The balance for Account 190 Accumulated Deferred Income Taxes has fluctuated significantly over the past several years as shown in the following table.

Table 36: Variation in Account 190 Accumulated Deferred Income Taxes 2003-2007[298]

Annual Report 12/31/03	23,657,397
Annual Report 12/31/04	908,430
Annual Report 12/31/05	22,789,457
Annual Report 12/31/06	(3,014,665)
Schedule B-6 3/31/07	14,834,002

The Company's response to the data request requesting explanations for the variances in Account 190 in the PUC Ohio Annual Report for 2004, 2005, and 2006 was a schedule showing the debits and credits to the deferred income tax balances from 12/31/2003 through 3/31/07. No additional explanations were provided for the significant variances from year to year.[299]

There were significant changes in the balances in Account 282 and 283 from 2004 through 2007 as shown in the table below.

Table 37: Deferred Income Tax Balances FERC Accounts 282 and 283, 2004-2007[300]

The East Ohio Company d/b/a Dominion East Ohio
Case No. 07-829-GA-AIR

Deferred Income Taxes Balances 2004-2007

Line No.	Account No.	Description	GPR 1-24 FERC 3/31/07	Annual Report 12/31/06	Annual Report 12/31/05	Annual Report 12/31/04
			(A)	(B)	(C)	(D)
		Total				
1	9282000	Accumulated DIT-Libr Depr	192,102,936	191,352,185	189,629,702	184,524,633
2	9283000	Accumulated DIT-Other	211,364,635	222,575,775	243,573,929	174,829,828
3		Total	403,467,571	413,927,960	433,203,631	359,354,461
		Change from Prior Year				
4	9282000	Accumulated DIT-Libr Depr	750,751	1,722,483	5,105,069	
5	9283000	Accumulated DIT-Other	(11,211,140)	(20,998,154)	68,744,101	
6			(10,460,389)	(19,275,671)	73,849,170	
		Percent Change from Prior Year				
7	9282000	Accumulated DIT-Libr Depr	0.39%	0.91%	2.77%	
8	9283000	Accumulated DIT-Other	-5.04%	-8.62%	39.32%	
9			-2.53%	-4.45%	20.55%	

[298] Sources include the Natural Gas Companies Annual Report for The East Ohio Company to the Public Utilities Commission for the years ended 12/31/04, 12/31/05, and 12/31/06 and Schedule B-6 of the Company's Application.
[299] Response to Data Request BRCS-DHM-02-005, attachment Account 190 Detail 2004-03 2007.xls.
[300] Workpaper *C(14)_Deferred Income Taxes.xls.*

The Company's response to the data request requesting explanations for the variances in Accounts 282 and 283 for 2004, 2005, 2006, and 2007 was a schedule showing the debits and credits to the deferred income tax balances from 12/31/2003 through 3/31/07. No additional explanation was provided.[301]

Findings

The Company provided reasonable explanation for the adjustments to deferred income taxes in regard to its filing in this proceeding. Explanations for the other items that did not have adjustments and explanations for significant variances from year to year were not provided.

Conclusions and Recommendations

The Company provided adequate support from its accounting records for the balances in deferred income taxes accounts. Although many of the components that are included within deferred income taxes reduce the Company's rate base, the Company should be required to provide additional explanation in its workpapers that support the balances that remain within deferred income taxes in its rate filings.

Rate Base Task C.15

Task C.15-The auditor will review and analyze the Applicant's proposed adjustments to operating income and rate base and trace them to supporting workpapers and source data.[302]

See the discussion in section Operating Income Task B.13 of this report.

[301] Response to Data Request BRCS-DHM-02-007, attachment Account 282-283 Detail 2004-03 2007.xls.
[302] Due to the similarities between Task B.13 and Task C.15, they will be discussed together in this report. See the discussion for Task B.13 in Section B. Operating Income of this report.

D. ALLOCATIONS

Audit Team

1. Michael J. McGarry, Sr. – Lead
2. Dan Salter
3. Tracy Mullinax – Support

Audit Objectives and Scope

Blue Ridge's audit objectives and scope as provided in the approved work plan included an evaluation of the following:

Task D.1-The auditor selected shall review the applicant's Corporate Allocation Manual (CAM) and verify that it has been properly applied to the test year and date certain valuations.

Review the information previously provided during these proceedings that related to this issue. Review the accounting for a representative sample of transfers of supplies and services from the utility to the non-regulated affiliates and confirm that the cost includes the energy utility's authorized rate of return and all overheads. Review the accounting for a representative sample of transfers of supplies and services from non-regulated affiliates to the utility and confirm that the cost includes the energy utility's authorized rate of return and all overheads. Identify the overheads and how they are applied by the utility to its labor loadings each year of the study period.

Task D.2-The auditor selected shall review any operating income and rate base jurisdictional allocation factors (state/federal), determine the basis of each factor, and render an opinion regarding the appropriateness of the allocation factor.

Request backup support for all allocators, validate calculations with underlying documentation, and compare to previous case and note any changes.

Allocations Task D.1

Task D.1-The auditor selected shall review the applicant's Corporate Allocation Manual (CAM) and verify that it has been properly applied to the test year and date certain valuations.

Background

The Cost Allocation Manual is the document by which a company identifies, defines, and describes the method by which it will assign costs. A utility's costs are allocated based on jurisdictional, functional, and provisional concerns. Allocation according to jurisdictional distinction occurs to separate costs of a utility that is serving more than one area of regulatory authority. Allocation of functional distinction separates costs based on service type. Provisional allocation is concerned with cost of service to specific customer classes.

All three allocation categories must function in accordance with regulatory requirements and organizational guidelines to ensure that none of the regulated entities and ratepayer classes is charged with costs that do not reflect the value of the service provided.

The Company's position within the overall corporate structure of Dominion Resources, Inc. (DRI) provides for interaction between and among affiliates. Most notably, Dominion Resources Services, Inc. (DRS) provides several operational services to the Company that are assigned by functional allocation.

Blue Ridge reviewed the various case documentation related to cost allocation, including the rate application, witness testimony, and previous case history. Additionally, fourteen initial data requests concerning the issue of Allocations were submitted to the Company.

Analysis

Blue Ridge began its verification of the allocation issue by reviewing the Cost Allocation Manual (CAM) of DRS to determine whether it has been properly applied to affiliate transactions. Blue Ridge requested access to the CAM and any associated orders, rules, regulations, plans, policies, or guidelines. The DRS CAM[303] contains the DRS Services Agreement, including a description of services, the method of allocation, and discussion of the associated allocation factors.

The Blue Ridge analysis of the CAM's application includes the following areas:

- Ensuring Training in Applying the CAM
- Ensuring Compliance with the CAM and Code of Conduct
- Ensuring the Proper Application of Functional Allocations
- Ensuring the Proper Labor Loadings/Overheads on Time Charges
- Ensuring the Authorized Rate of Return on Affiliate Transactions

Ensuring Training in Applying the CAM

Blue Ridge reviewed affiliate transaction training to verify that the Company was providing personnel with the knowledge of proper reporting requirements.

In response to requests concerning the training process for affiliate transactions, the Company provided examples of training materials, such as a DRS employee training presentation showing detailed instruction in Cost Center and WBS element charging.[304] The presentation was included in an employee-required class titled "Time and Expense Charging," which is a Learning Management System module after which a test is given in which employees must earn a grade of 80%. Additionally, Company training records were provided for the years 2004 through 2007 for Standards of Conduct training which

[303] Response to Data Request BRCS-DWS-01-002.
[304] Response to Data Request BRCS-DWS-01-010.

relates to the uniform application of tariffs, gas transportation, separation of operating and marketing activities, etc.[305]

Blue Ridge also reviewed the Code / Standards of Conduct internal audits for the years 2005 and 2007.[306]

Ensuring Compliance with the CAM and Code of Conduct

Blue Ridge requested access to the Company's internal audit reports[307] to ensure that the Company was reviewing compliance with the CAM and Code of Conduct as well as to review any findings resulting from the audits. According to the Company's response, [redacted].[308]

[redacted].

Dominion Resources, Inc. has identified seven Codes and Standards of Conduct which affect operations among affiliates. All employees are placed within a Code of Conduct Group that specifies which of the seven Codes control the employee's activities. The seven Codes include:

- The FERC Electric Code of Conduct
- The Virginia Electric Retail Access Codes of Conduct
- The Virginia Electric Functional Separation Code of Conduct
- The North Carolina Electric Code of Conduct
- The Pennsylvania Gas Local Distribution Company Standards of Conduct
- The Ohio Gas Local Distribution Company Standards of Conduct

[redacted].

[redacted]

[305] Response to Data Request BRCS-DWS-01-011.
[306] CONFIDENTIAL Response to Data Request BRCS-GPR-01-019.
[307] CONFIDENTIAL Data Request BRCS-GPR-01-019.
[308] CONFIDENTIAL Response to Data Request BRCS-GPR-01-019.

[redacted]

[redacted]

The Dominion Ethics Program requires that each employee reports "any actual or suspected misconduct, illegal activity, or violations of policies, procedures, laws or regulations."[309] According to the Company,[310] during the years 2002 through 2007, there have been no reported violations involving:

- Allocation of costs or other affiliate transactions related to the Company
- Actions by Service Company or other affiliate employees regarding amounts charged to the Company
- Actions by Company employees regarding amounts billed to affiliates
- The Company's Code of Conduct

Ensuring the Proper Application of Functional Allocations

Blue Ridge examined the CAM documents provided[311] to become acquainted with the allocation of DRS services costs to the Company.

An approved DRS Services Agreement must be executed between DRS and any Dominion Resources, Inc. (DRI) affiliate receiving services from DRS. The DRS Services Agreement is contained within the CAM. In the Service Agreement, DRS states that it aligns costs billed to affiliates in such a way so as to ensure that those affiliates whose operations give rise to the costs also pay for those costs through proper charging and billing. Thus, services performed directly for a particular affiliate are directly billed to that affiliate. Services performed for multiple affiliates are apportioned or allocated to those affiliates in a fair and equitable manner.

[309] Response to Data Request BRCS-DWS-01-004, *Dom Ethics Program.pdf.*
[310] Response to Data Request BRCS-DWS-01-009.
[311] Response to Data Request BRCS-DWS-01-002.

DRS directs the accounting of incurred costs based on certain characteristics.

DRS Non-Service-Related Cost
If DRS incurs a cost that is the responsibility of the Company but is not the result of a DRS-provided service, the cost will be recorded directly on the Company's cost center or Work Breakdown Structure (WBS) element or, if an approved Convenience Payment exists, DRS will make the payment to the vendor and then record a receivable from the Company.

DRS Service-Related Cost - DRS employee or admin contractor cost
If the incurred cost is for a DRS employee or admin contractor, the cost is recorded on the appropriate DRS cost center.

DRS Service-Related Cost – for service to the Company
If the incurred cost is for a service to DEO, the cost is recorded directly to a DRS direct billing WBS element. A direct billing WBS element has a billing suffix identifying the affiliate. For example, the Company's identifying characters are EOG, which stands for East Ohio Gas. Thus, for example, when a cost for auditing services is incurred, the charge is made to the WBS element AUDIT.EOG.

DRS Service-Related Cost – for general services to affiliates
If the incurred cost is for a DRS service, but not specifically for only DEO, the cost is recorded directly to a DRS allocation billing WBS element. All allocation billing WBS elements are identified with the suffix ALLOC. Thus, for example, when a cost for employee relations is incurred, the charge is made to the WBS element HR.ALLOC1. The HR.ALLOC1 total will be allocated to affiliates as outlined in the CAM—in this case, by employee headcount.

The CAM also identifies and defines twenty-six (26) functional service categories provided by DRS.

1. Accounting
2. Auditing
3. Legal/Regulatory
4. Information Technology
5. Software Pooling
6. Employee Benefits
7. Human Resources
8. Operations
9. Executive and Administrative
10. Business and Operations Services
11. Exploration and Development
12. Risk Management
13. Marketing
14. Medical
15. Corporate Planning
16. Supply Chain
17. Rates
18. Research
19. Tax
20. Corporate Secretary
21. Investor Relations
22. Environmental Compliance
23. Customer Services
24. Energy Marketing
25. Treasury/Finance
26. External Affairs

Additionally, the CAM identifies the methods for allocating DRS services costs to affiliates. These methods are displayed in the following chart.

Table 38: DRIS Allocation Methods[312]

	Services	Service Department or Function	Basis of Allocation
1	Accounting	*Accounting:*	
		Payroll Processing	# of employees at end of preceding year
		Accounts Payable Processing	# of accounts payable docs preceding year
		Fixed Assets Accounting	Fixed assets added, retired or transferred preceding year
		Accounts Receivable Processing	# of payments preceding year
2	Auditing		
3	Legal/Regulatory		
4	Info Technology	*Information Technology, Electronic Transmission, and Computer Services:*	
		LDC/EDC Computer Applications	# of customers at end of preceding year
		Other Computer Applications	# of users or usage of specific computer systems at end of preceding year
		Network Computer Applications	# of network devices at end of preceding year
		Telecommunications Applications	# of telecommunications units at end of preceding year
5	Software Pooling		
6	Employee Benefits	*Employee Benefits/Pension Investment:*	
		Employee Benefits/Pension Invest	# of employee and annuitant accounts at end of preceding year
7	Human Resources	*Human Resources:*	
		Human Resources	# of employees at end of preceding year
8	Operations		
9	Exec & Admin		
10	Business & Ops Srvcs	*Business and Operations Services:*	
		Energy Services	Energy sale and deliveries for preceding year
		Facility Services	Square footage of office space at end of preceding year
		Fleet Administration	# of vehicles at end of preceding year
		Security	# of employees at end of preceding year
		Gas Supply	Gas volumes purchased for each Dom Co for preceding year
11	Exploration & Dev		
12	Risk Management	*Risk Management:*	
		Risk Management	Insurance premiums for preceding year
13	Marketing	*Marketing:*	
		Shared Projects	Annual marketing plan expenses for preceding year
		Other Indirect Costs	Marketing direct & shared proj costs of each Dom Co for preceding year
14	Medical	*Medical:*	
		Medical Services	# of employees at end of preceding year
15	Corporate Planning	*Corporate Planning:*	
		Corporate Planning	Total capitalization recorded at end of preceding year
16	Supply Chain	*Supply Chain:*	
		Purchasing	Dollar value of purchases for preceding year
		Materials Management	Material inventory assets at end of preceding year
19	Tax	*Tax:*	
		Tax Accounting and Compliance	Sum of total income and deductions on the last federal tax return filed
20	Corporate Secretary		
21	Investor Relations		
22	Environmental Compliance		
23	Customer Services	*Customer Services:*	
		Customer Payment Processing	# of customer payments processed during preceding year
		Other Customer Services	For metering, # of meters for preceding year; otherwise # of customers for preceding year
24	Energy Marketing		
25	Treasury/Finance	*Treasury/ Finance:*	
		Treasury and Cash Management	Total capitalization recorded at end of preceding year
17	Rates	Rates	Total regulated company operating expenses, excluding purchased gas expense, purchased power expense (including fuel expense), other purchased products and royalties, for preceding year
18	Research	Research	Gross revenues recorded during preceding year
26	External Affairs		

[312] Workpaper *D(1) Allocation Methods.xls.*

Blue Ridge initially requested that the Company provide all transactions between Dominion affiliates and the Company[313] from which to select a sample set of transactions for review and validation. This sample review was intended to verify (1) that labor loadings were properly applied, (2) that functional allocations were correctly applied, and (3) that DE-Ohio's transaction costs included the authorized rate of return. In discussions with Company representatives, Blue Ridge learned that the Company does not make the functional allocation at the transaction level, thus rendering the source records inadequate for the functional allocation verification portion of the analysis.

In response to Blue Ridge's transaction request, the Company provided a summary of affiliate transactions per month from January 2004 through date certain March 2007.[314] Additionally, the Company provided a summary by functional service category also by month from January 2004 to date certain March 2007.[315] Blue Ridge performed a trend analysis on this summary to examine any significant increases in categories from year to year.[316] Discussion of the trend analysis is included in section Rate Base Task C.16 of this report.

Additionally, Blue Ridge received documents providing the backup used to create the most recent functional allocators.[317]

In discussion with the Company Director of Financial and Business Services, Blue Ridge learned that control of DRS costs was maintained by means of a monthly report indicating plan versus actual costs of all DRS cost categories to Dominion Resources divisions including Gas Delivery.[318] Blue Ridge reviewed the reports for the months January through March 2006.[319]

Since allocations are applied at a level above DOE departments, DOE department managers do not match DRS charges to specific departmental services received. Furthermore, individual managers have little input to their budgets with regard to DRS costs. Management analysis is limited to actual to budget variances. The only real managers of DRS costs are the functional managers within the DRS organization. The result is that DEO has limited control over DRS cost in application to the test year.

DRS does perform some benchmarking studies to ensure that costs are in line with industry costs. Blue Ridge reviewed the DRS benchmarking studies, including one on Fleet Management (2005), one on Gain (2006), and a series on O&M Costs per Square Foot (2003-2006).

[313] Data Request BRCS-DWS-01-008.
[314] Response to Data Request BRCS-DWS-01-008.
[315] Response to Data Request BRCS-DWS-01-008.
[316] Workpaper *D(1) DRS Billings Trend.xls.*
[317] Response to Data Request BRCS-DWS-03-003 (confidential).
[318] Bond & Fines - Interview on 080110.
[319] Response to Data Request BRCS-DWS-03-002 (confidential).

Ensuring the Proper Labor Loadings/Overheads on Time Charges

Company employees enter time on a weekly basis through an Employee Self-service time entry process. Printed SAP time reports are used for the approval process which is performed at least monthly. Time is charged to appropriate business units and/or projects using WBS elements. Employees undergo training titled "Time and Expense Charging," a Learning Management System module after which a test is given in which employees must earn a grade of 80%. The training class covers topics such as the definition of a WBS element, how and why time and expenses are charged to WBS elements, and the responsibility of management in providing WBS elements to their employees.

DEO labor loadings include benefits, incentives, and payroll tax at separate rates for salaried and hourly employees. The following chart displays the rates as provided by the Company.[320]

Table 39: DEO Labor Loadings[321]

	Benefits Load	Incentive Load	Payroll Tax Load
Salaried Employees	29.44%	15.00%	7.89%
Hourly Employees	37.07%	3.00%	7.89%

The percentages for the labor loadings are initially established at the beginning of each year based on budgeted information. The percentages are updated during the year if there are significant changes in expected benefit expenditures for the remainder of the year.

Blue Ridge also reviewed overhead and surcharges per month for affiliated transactions rendered by DEO.[322]

Ensuring the Authorized Rate of Return on Affiliate Transactions

One of the purposes of Blue Ridge's transaction data request[323] was to determine whether affiliate transactions included the Company's authorized rate of return. According to the Company's response, affiliate billings rendered by DEO do not include a component for an authorized rate of return, but are charged at cost. This statement is consistent with the CAM which adds that charging affiliate transactions at cost is an SEC rule.

Findings

In performing analysis of applicable documents, Blue Ridge noted several observations/findings related to this Allocations task. The findings are grouped below in the same format as the discussion of analysis above.

[320] Response to Data Request BRCS-DWS-01-012.
[321] Workpaper *D(1) Labor Loadings.xls*.
[322] Response to Data Request BRCS-DWS-06-001.
[323] Data Request BRCS-DWS-01-008.

Ensuring Training in Applying the CAM

Upon review of the 2007 Code / Standards of Conduct internal audit, Blue Ridge noted the auditor's observation that [redacted].

Ensuring Compliance with the CAM and Code of Conduct

Blue Ridge found no violation of CAM and Code of Conduct application to the current rate case. However, Blue Ridge's review of the internal audit reports for the 2005 and 2007 Code / Standards of Conduct as well as the 2003 Affiliated Gas Procurement Transactions revealed [redacted], lack of procedural requirement can lead to insufficient knowledge when called upon to employ state standards of conduct.

Ensuring the Proper Application of Functional Allocations

Blue Ridge found that the functional services list provided in the CAM and the method of application of incurred costs to DEO outlined in the CAM were reasonable and appropriate. Furthermore, the DRS costs charged to DEO are in line with expectations and provide confidence of correct application to the current rate case. Those costs which exhibited large percentage increases in recent years through date certain (March 31, 2007) were adequately explained by the Company.[325] Backup to the functional allocators appeared reasonable. And the monthly plan versus actual reports reviewed provided additional confidence of the exercise of control.[326]

Although individual DEO managers have little absolute control over DRS charges to their departments, several controls are in place to provide a level of confidence that DRS charged costs are appropriate. First, the DRS allocation process is under regular audit evaluation.[327] [redacted]. Second, except as noted in Task C-16, the trend of service costs to DEO from year to year has been relatively consistent.[328] The few instances of greater than normal increases are discussed in section Rate Base Task C.16. Third, benchmarking studies are being performed to ensure best practices and reasonable costs.[329]

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324 CONFIDENTIAL Response to Data Request BRCS-GPR-01-019.
325 Response to BRCS-DWS-05-001, -002, -003, -004, -005, and -006.
326 CONFIDENTIAL Response to BRCS-DWS-03-002.
327 CONFIDENTIAL Response to Data Request BRCS-GPR-01-019.
328 Workpaper *D(1) DRS Billings Trend.xls*.
329 CONFIDENTIAL Response to BRCS-DWS-03-006.

Ensuring the Proper Labor Loadings/Overheads on Time Charges

Blue Ridge found that the labor loadings provided by the Company that were based on 2007 forecast were consistent with historical labor loadings as calculated in the Supplemental #18, Schedule C-9. Additionally, overheads/surcharges on affiliated transactions appeared appropriate.[330]

Ensuring the Authorized Rate of Return on Affiliate Transactions

Blue Ridge found no inconsistencies with the Company's policy of affiliate transactions at cost.

Conclusions and Recommendations

Based on the Allocations findings noted above, Blue Ridge makes the following recommendations.

Ensuring Training in Applying the CAM

Blue Ridge recommends that the Company's Legal Services department should develop and institute a procedure by which Code of Conduct training is required of and performed for all applicable Company employees.

Ensuring Compliance with the CAM and Code of Conduct

Due to the repeated observation that [redacted], Blue Ridge recommends that a thorough review and enhancement of training procedures related to codes of conduct, affiliated transactions, and CAM implementation be conducted to ensure that all Company employees are familiar with requirements, providing reasonable assurance that transactions will be executed in compliance to the governing documents. This recommendation is intended to support future assurance of proper application of the CAM and Codes of Conduct. As mentioned in the Findings section, Blue Ridge has not found abnormalities in application of policies and procedures directed toward the current rate case test year figures.

Ensuring the Proper Application of Functional Allocations

Based on the documents reviewed and interviews, Blue Ridge concludes that the functional allocations by DRS are at a reasonable cost and reasonably applied. Based on the audits and benchmarking studies, DRS is exercising control over cost and application of its services. However, to ensure consistent control across all service categories, Blue Ridge recommends development of a regular benchmarking study schedule (benchmarking studies of all service categories on a five to seven year rotational basis) so that cost levels of all service categories are regularly monitored.

[330] Response to BRCS-DWS-06-001.

Ensuring the Proper Labor Loadings/Overheads on Time Charges

Blue Ridge concludes that labor loadings have been properly applied.

Ensuring the Authorized Rate of Return on Affiliate Transactions

Blue Ridge concludes that affiliate transactions rendered by DEO at cost without including the authorized rate of return is a reasonable practice.

Allocations Task D.2

Task D.2-The auditor selected shall review any operating income and rate base jurisdictional allocation factors (state/federal); determine the basis of each factor, and render an opinion regarding the appropriateness of the allocation factor.

Jurisdictional allocation factors are used to assign costs of a utility to the correct regulatory jurisdiction. All DEO's costs are allocated 100% to the jurisdiction regulated by the PUCO.[331]

Blue Ridge reviewed the sources and calculations making up the cost of service allocators.[332] These sources support Schedule E-3.2 of the Standard Filing Requirement.[333]

Findings

Blue Ridge found jurisdictional allocation at 100% as expected. The cost of service allocators appeared appropriate as well.

Conclusions and Recommendations

Blue Ridge concludes that jurisdictional and operating income allocations are appropriate.

[331] Response to Data Request BRCS-DWS-01-014.
[332] Response to Data Request BRCS-DWS-06-002.
[333] Supplemental #18, Schedule E-3.2.

OTHER INDEPENDENT ANALYSIS

Rate Base Task C.16

Task C.16-Other independent analysis will be performed as the auditor and/or Staff consider necessary under the circumstances.

Issue 1: Billing Process, Revenue Validation, & Customer Service Testing

Background

Utility revenues are derived by applying a rate to an amount of product usage. Though perhaps an over-simplistic description, it underscores the importance that usage data and rates have on revenues. If usage is inaccurate or rates are not properly applied, the resulting revenues will be inaccurate. Given the importance of test year revenues to the level of rate increase requested by the Company, it is critical for the test year revenues (and, in turn, the test year usage and rates) to be accurate. Blue Ridge conducted an analysis of the Company's billing process from its beginning (i.e., the collection of usage data) to its end (i.e., revenue booked to the Company's General Ledger accounts) to determine whether the process used to generate the Company's revenues is sound. Blue Ridge also examined billing records from the three actual months of the test year to determine whether the general ledger bookings for those months are reasonably accurate in relation to the records from the Company's billing systems.

Analysis

Blue Ridge interviewed Company personnel to understand the Company's billing cycle process from collection of usage data (i.e., meter reading) through the production and distribution of customers' invoices and the recording of revenue on the Company's general ledger. Blue Ridge interviewed the following Company personnel: Director of Customer Billing & Payment, who is responsible for billing/payment activities (e.g., payment processing) for five states for Dominion Resources, Inc. (DRI); IT Project Manager for Customer Care System (CCS), who is responsible for customer billing and data flow from meter reads to general ledger postings; and the IT Systems Analyst, who is responsible for ensuring that rates are applied properly in the Company's systems for billing purposes.[334] Blue Ridge also interviewed the Director of Customer Service Centers, who manages inbound customer call service centers and account initiation set up.[335]

Blue Ridge issued follow-up data requests to these interviews seeking information on billing exceptions reviewed by the Company, customer complaints, and bill validation.[336] Blue Ridge reviewed the responses provided by the Company to these data requests.

[334] Merritt, Culp, Bauer & Rice - Interview on 080111.
[335] Fanelly - Interview on 080110.
[336] Data Requests BRCS-WF-03-028, BRCS-WF-03-029, and BRCS-WF-03-030.

The Company explained that the billing process—from meter reading usage data collection to the recording of revenue in the general ledger accounts—is performed automatically in the Company's CCS.[337] Usage data is collected in a number of ways, including manual reads, in which a Company meter reader goes to the customer's premises and uses a hand held device to collect usage data from the customer's meter; remote reads, in which reads are collected without visiting the customers' premises (e.g., automated meter reading (AMR) technology), and through customer self-reads, in which customers read their own meter and send the readings to the Company online.[338] The Company is in the process of an Automated Meter Reading (AMR) deployment initiative[339] and plans to deploy AMR fully in five years. High/low tests are performed on the usage data regardless of the method used to collect the usage data. Any outliers to the high/low test are investigated by the Company, and estimates are used by the Company for these outlier reads to ensure that the customer is billed that month. Reads that are within the high/low parameters continue on through the CCS system. After the bill close date, the data is sent downstream in the Company's systems to the General Ledger[340] and bill production. Customer bill printing and mailing for all companies (gas and electric) is done in-house by DRI in Richmond, Virginia.[341]

The Company established a three-day billing window with an objective of rendering a bill within a 24-hour timeframe of the meter read. For example, if a meter is read on a Monday, usage data is uploaded from the handheld device on Monday night, and a bill is printed and mailed on Tuesday. The 24-hour period applies to bills that run smoothly through the system and may not apply to reads with exceptions that could delay the rendering of the bill to a future billing cycle.[342] If a meter is not read on the revenue cycle date, the Company will issue an estimated bill. Customers' bills are "trued up" each time the Company gets an actual read following an estimated bill, which is done either automatically in the CCS system or manually for customers on an Energy Choice rate.[343]

The Company's customer services group interfaces with customers regarding a host of billing-related issues. The Company's Customer Service Center handles inbound

[337] The CCS system was initially deployed in 1997 and fully implemented in 2000, and is separate and distinct from SAP. Fanelly - Interview on 080110.
[338] Manual reads constitute about 60% of total reads and remote reads comprise the remaining 40%. Manual reads are done bi-monthly for mass market residential customers and the frequency of reads for other customers can vary (e.g., monthly). The Company will do monthly reads when it is fully AMR-capable. Fanelly - Interview on 080110.
[339] The Company installed 130,000 AMRs in 2007. Fanelly - Interview on 080110.
[340] A direct interface exists between the Company's General Ledger and SAP system, and a General Ledger report can be run in the Company's CCS system.
[341] Currently, the IT group is responsible for printing customer bills, and Customer Billing & Payment is responsible for stuffing and mailing bills (as well as ancillary functions such as monitoring postal discounts). The Company is examining combining the two functions under the same group. Merritt, Culp, Bauer & Rice - Interview on 080111.
[342] There are 21 billing cycles in a month.
[343] Fanelly - Interview on 080110.

customer calls related to billing issues. The Company outsources outbound customer calling[344] for such issues as credit call activity, meter reading, Energy Choice, and access to premises. The customer services group has limited authority to resolve billing problems when customers call them, though the group's representatives can cancel/rebill in the case of a bill overestimation. More complex billing issues are referred to the customer billing group for resolution. According to the Director of Customer Service Centers, the number of calls to customer service and the duration of those calls are important to the Company, and the Company expects a reduction in the number of customer calls as well as a reduction in the call duration as the Company's AMR deployment footprint grows.

Controls are in place in the Company's billing process, and those controls will be increasing in the near term. First, high/low tests are conducted to test the accuracy of meter reads. If a meter read falls outside the high/low parameters set by the Company, it does not flow through the system, and the outlier is instead sent for analysis and resolution by the Company. A high/low test is performed on the meter read by the handheld meter reading device, and another high/low test is performed when the data is uploaded into CCS. Second, the Company performs an accuracy check on a sample of customer bills on a monthly basis. Blue Ridge requested information related to the Company's monthly accuracy check of customers' bills[345] and reviewed the information provided by the Company in response. The Company's response explains how it verifies rate changes in the CCS and the accuracy of customer bills and includes examples of reviews performed on the Company's gas rates (by rate plan) during the three actual months of the test year. Third, the Company tracks customer complaints through monthly reports – complaints that the Company described as "minimal" in 2007 and mostly related to time to meter read and backfill (i.e., delay of actual reading) rather than accuracy of the bill itself. Blue Ridge requested information related to customer complaint reports for the three actual months of the test year[346] and reviewed the information provided by the Company in response. The Company's response included the Customer Complaint reports prepared by the Company for January through March 2007, which include the number and cause of customer complaints and show that the number of customer complaints has decreased for each of the three actual months of the test year compared to the same three month period for the previous year. The Company's response also includes a summary of the resolutions to these complaints.[347] Fourth, the Company's billing administrator group conducts desk audits (described below). Fifth, the Company has procedures in place for revenue assurance and theft of service. If a customer's service has not been turned off for nonpayment, the Customer Billing & Payment department addresses an issue related to revenue assurance/theft of service as a billing exception. For example, if CCS shows a gas meter is disconnected, but it is not turned off in the field, Customer Billing & Payment would address this issue to ensure

[344] The Company outsources outbound calling to West Interactive Services. Outbound calling is about 1/3[rd] of total calling activity. Fanelly - Interview on 080110.
[345] Data Request BRCS-WF-03-030.
[346] Data Request BRCS-WF-03-029.
[347] Response to Data Request BRCS-WF-03-029, filename *Issues Resolution Jan-Mar 07.xls*.

that usage is captured and billed. If the gas meter has been turned off for nonpayment, the issue is addressed by the credit collections group in Energy Diversion.[348]

Controls also exist in the customer service process. Quarterly assurance monitoring is performed to ensure regulatory compliance with DEO's tariff terms and conditions. Customer Service representatives (CSRs) are also tested for their handling of customer calls. CSRs are subject to "monitors" in which calls are recorded and checked to ensure procedures are followed. Each monitor is scored, and feedback is provided to the CSR within a 24-hour timeframe. The Company also performs this monitoring testing on its third-party vendor who does outbound calling and has a contractual obligation to the Company to score at 85% or above.

When exceptions to the billing process arise, the Company handles them according to two exception categories. The first category is "work exceptions" or "work queues" in which the customer bill requires a review before it goes to the customer (i.e., pre-bill issuance). The second category is "informational exceptions" which includes issues related to bills that do not pertain to the bill amount. When these exceptions arise or a meter read falls outside the high/low test parameters, personnel based in Richmond, Virginia (i.e., billing administrators) review the problem, make corrections, and check the meter reading. The billing administrator group has two supervisors—one is responsible for the exceptions resolution process and the other is responsible for quality control. The quality control supervisor conducts quality/desk audits to analyze how billing administrators are resolving exceptions and to maximize bill accuracy and timeliness.[349] The Company has a goal of 95% of exceptions worked within 10 days and the additional 5% worked within 30 days.[350] The Company creates a daily report on exceptions that is sent to the billing group.[351]

The Company's bad debt collection policy involves exhausting collection efforts that are conducted within a 60 day window, after which the bad debt is referred to a collection agency. In an interview with the Director of Customer Billing & Payment, Blue Ridge was informed that the Company is starting a new bad debt procedure[352] whereby customers that are determined to be highly "collectible" will go to a DEO-sponsored pre-collection agency before being referred to an actual collection agency. This new process is designed for the Company to be able to collect from customers that are ultimately likely to pay, rather than selling it off as bad debt.

[348] The Customer Service group identifies potential areas/accounts that need investigation for revenue assurance security or theft of service purposes and then forwards those to the Energy Diversion group for investigation.
[349] The Company stated that there were no reports available from the Company that tracked the results of the desk audits.
[350] Merritt, Culp, Bauer & Rice - Interview on 080111.
[351] Blue Ridge requested a copy of a daily report from each of the actual three months of the Company's test year (data request BRCS-WF-03-028). The Company states in response that the requested information was not captured and reported for Ohio until mid-2007. Response to Data Request BRCS-WF-03-028.
[352] This process was a work-in-progress for DOE in January of 2008, and was already implemented on the electric side of the Company's business.

In an interview, the Director of Customer Billing & Payment stated that one of the goals for 2008 was to increase the documented controls related to the Company's billing process. The Company explained that, although problems were not experienced in the Company's billing process, it recognized in 2007 a need for increased documented controls. Currently, a quality team holds responsibility for documenting rules, Sarbanes-Oxley requirements, and the Company's response to these requirements.

Blue Ridge tested the accuracy of the revenues recorded in the Company's General Ledger accounts. Blue Ridge issued discovery requests to the Company seeking billing records[353] and reviewed the responses and supporting documentation provided by the Company. This information included supporting files from the Company's CCS and Special Billing System (SBS)[354] systems and data on the associated general ledger activity. Blue Ridge held discussions on site in Cleveland, Ohio with Company personnel responsible for the CCS and SBS reports to increase the auditors' understanding of the data provided by the Company and how that data is compiled and ultimately flows through to the Company's general ledger bookings. Blue Ridge requested and the Company provided additional supporting CCS and SBS documentation for the three actual months of the test year (January through March 2007). The Company also provided a "Revenue Bookings" worksheet that showed how the CCS and SBS data for these three months of the test year flows through to the actual trial balances for these three months. In short, the trial balance postings for a particular month consist of the following primary components: (1) reverse out prior month's SBS estimate with prior month's SBS actual, (2) add current month's SBS estimate, (3) reverse out prior month's CCS estimates with prior month's CCS actuals, (4) add current month's CCS estimate, and (5) reverse out prior unbilled transportation with current unbilled transportation. Blue Ridge traced these primary components from the SBS and CCS supporting documentation to the Revenue Bookings worksheet and then verified the totals of the Revenue Bookings worksheet in relation to the Company's trial balances for the three months of the test year.[355]

Findings

Blue Ridge did not identify any significant shortcomings in the Company's billing process, revenue validation process, or customer service process. The Company has numerous controls in place throughout the process to ensure that the revenue that is ultimately booked to the Company's accounts is based on accurate information and that exceptions are investigated and resolved in a proper, timely manner. The Company also creates numerous data and reports to observe the Company's performance on these processes and to identify and resolve any potential problems. Blue Ridge was able to verify the revenue bookings to the Company's General Ledger accounts and trial balances in relation to the supporting billing records, providing further support that the Company's processes are satisfactory. Further, the Company's initiative for 2008 to

[353] Data request BRCS-GPR-01-007.
[354] SBS includes high pressure customers such as industrial, commercial, and apartment buildings.
[355] The annotated version of the Revenue Bookings worksheet is provided as Workpaper *C(16)_Revenue Bookings_Jan-Mar_07.pdf.*

increase the documented controls of the Company's billing process should identify any issues that may exist in the Company's billing process in relation to applicable requirements, which will be of further benefit to the Company's billing process.

Conclusions and Recommendations

Blue Ridge concludes that the Company's billing, revenue validation, and customer service procedures are reasonable and have sufficient controls in place to ensure that customer bills as well as the revenue recorded on the Company's General Ledger is reliable. Blue Ridge recommends that the results and implementation of the Company's 2008 initiative to increase documented controls of the billing process be reviewed in the future to determine whether the Company finds any shortcomings in the Company's billing process during this initiative and, if so, how any shortcomings are addressed by the Company.

Issue 2: Account 923 – Dominion Resources Services, Inc. (Service Company) Charges to Dominion East Ohio

Background

At Staff's request, Blue Ridge initiated a review of the costs being charged to FERC Account 9923000 (or Account 923). This account accumulated administrative and general costs associated with outside services. It is the primary account where DEO records costs charged to DEO by the service company – Dominion Resources Services, Inc. (DRS).

As stated in the company's filing, DRS "is an affiliate of DEO that provides shared services to all DRI [parent company] subsidiaries and business units."[356] DRS provides a number of services, including "Corporate Secretary; External Affairs; Shared Services (Fleet, Facilities Management and Supply Chain Management); Information Technology and Telecommunications; Human Resources; Legal; Six Sigma; and Treasury and Financial."[357]

In 2007, DEO recorded $60,616,259 of DRS costs for various services in Account 923. During 2006, DEO recorded $51,838,617 of DRS costs for those same services. Therefore, the 2007 service company costs recorded by DEO constitute an increase of $8,777,624 (or 16.9%) over year 2006. The Company's test year amount for Account 923 is $58,709,255.[358]

Analysis

To understand the costs recorded in Account 923 that are charged to DEO by DRS, Blue Ridge issued data requests seeking an itemization of the outside service costs recorded in

[356] Direct Testimony of Jeffrey Murphy, p. 6, lines 5-6.
[357] Direct Testimony of Jeffrey Murphy, p. 6, lines 9-12.
[358] See WPC-2.1, excel row 96.

Account 923 for the test year and five previous years,[359] further detail on the costs allocated to DEO by DRS,[360] as well as audits performed on service costs charged by DRS.[361] The Company provided responses to these discovery questions, including supporting documentation, which the auditors reviewed. Blue Ridge also interviewed Company personnel to increase Blue Ridge's understanding of the costs charged to DEO by DRS.[362]

Specific to the Account 923 costs, Blue Ridge performed a comparative analysis of the outside services expenses recorded by DEO in Account 923 for the period of 2002-2007 to identify trends in Account 923 bookings over time. Blue Ridge also compared the Account 923 costs at a more granular level (i.e., by service category) to identify the primary drivers of the $8,777,642 increase in Account 923 costs recorded by DEO in year 2007 over year 2006.

A summary of the annual Account 923 bookings from 2002 through 2007 is provided in the table below.

Table 40: DEO Outside Services Trend[363]

TREND OF DOMINION EAST OHIO OUTSIDE SERVICE EXPENSES IN FERC ACCOUNT 923
FOR THE YEARS 2002 - 2007

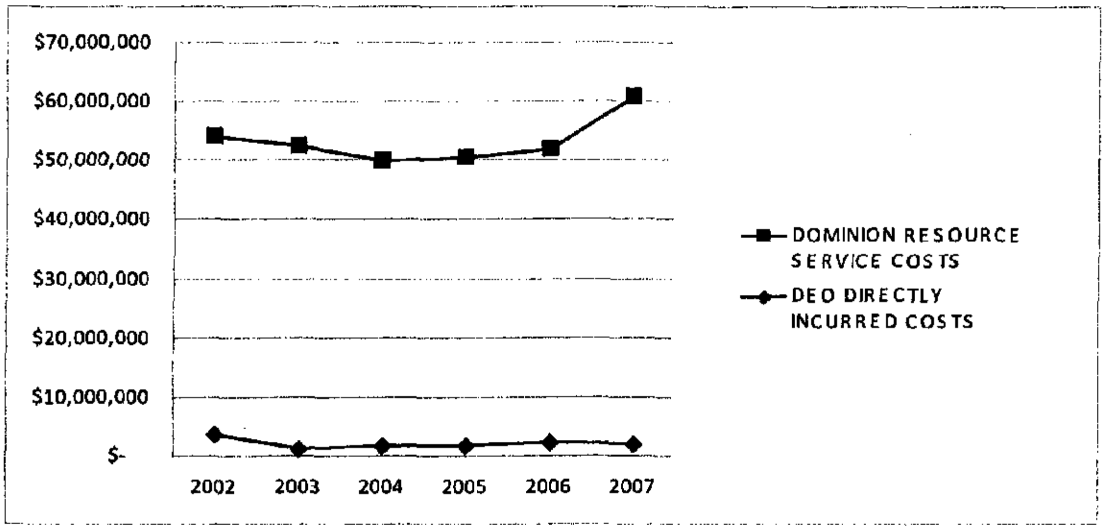
	2002	2003	2004	2005	2006	2007
DEO DIRECTLY INCURRED COSTS	$ 3,483,247	$ 1,105,970	$ 1,693,514	$ 1,744,020	$ 2,188,790	$ 2,039,789
DOMINION RESOURCE SERVICE COSTS	$ 53,910,240	$ 52,254,956	$ 49,791,010	$ 50,447,912	$ 51,838,617	$ 60,616,259
OTHER	$ (4,405,428)	$ (3,289,984)	$ (2,884,213)	$ (3,445,128)	$ (2,311,702)	$ (3,943,488)
TOTAL FERC ACCOUNT 923 (9923000)	$ 52,988,058	$ 50,070,942	$ 48,600,311	$ 48,746,804	$ 51,715,706	$ 58,712,560

This table shows that the Company recorded more for Account 923 in 2007 than in any other year of the time period. The total Account 923 in 2007 was 11% higher than the next highest year (2002) and almost $7 million (or 13.5%) higher than 2006. The 2007 Account 923 balance is also $8,288,196 (or 16.4%) greater than the five-year average of 2002-2006. Notably, the Company's proposed test year amount for Account 923 of $58,709,255[364] is very close to the 2007 actual amount of $58,712,560 (the 2007 actual amount is 0.0056% greater than the test year amount). Therefore, the comparisons of the 2007 actual amount to the prior historical data hold equally true for comparisons of the Company's proposed test year amount for Account 923 to the historical data.

[359] Data Request BRCS-WF-04-001.
[360] Data Requests BRCS-DWS-01-002, BRCS-DWS-01-008, BRCS-DWS-05-001 through -006, and BRCS-WF-04-002.
[361] Data Request BRCS-DWS-01-005.
[362] Bond & Fines - Interview on 080110.
[363] Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls.*
[364] See WPC-2.1, excel row 96.

This table also shows that between 2006 and 2007, DEO directly incurred costs decreased by $149,000 (or about 7%), while DRS services costs billed to DEO increased by $8,777,642 (or about 17%).[365] The 2007 total amount of DRS services costs is the highest amount in the six-year study period, is $6,706,019 (or 12.4%) higher than the next highest year (2002), $8,777,642 (or 17%) higher than 2006, and $8,967,712 (or 17.4%) higher than the 5 year average for 2002-2006. The chart below depicts the DRS services costs and DEO directly incurred costs for the six year period of 2002-2007.

Figure 20: Services Cost Trend[366]



This chart shows that while there was a small dip in costs (both DRS services costs and DEO directly-incurred costs) between 2002 and 2003, the most noticeable departure from trend is the increase in DRS services costs between 2006 and 2007.

To identify the source of the observed increase in DRS services costs charged to DEO between 2006 and 2007, Blue Ridge compared the Account 923 costs by service category. This comparison shows that four service categories comprise $7,724,826 of this increase (or 88% of the total increase from 2006 to 2007). The four service categories are: (1) Executive/Administrative Compensation, (2) Customer Service, (3) Miscellaneous and (4) Information Technology.[367]

365 Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls*, Tab *DRS Comparison.*

366 Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls.*

367 Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls* shows a comparison of charges from DRS to DEO for the period 2002-2007, sorted by 2007 increase over 2006 (highest to lowest).

1. **Executive/Administrative Compensation**

2007: $8,608,207
2006: $5,780,468
Increase: $2,827,819 or 48.9%

Approximately $400,000 of the increase of 2007 over 2006 for Executive/Administrative Compensation is due to one-time adjustments that reduced expenses in March 2006. The Company indicates in response to discovery[368] that the Compensation, Governance, and Nominating Committee of the Board of Directors approved the 2006 long-term compensation awards for Dominion's officers on March 31, 2006, which consisted of a restricted stock grant and a cash performance grant with the expense amortized over the service period, beginning April 2006. In March 2006, one-time adjustments were made for the executive compensation liability reducing that expense.

Based on Blue Ridge's review of DEO's 2007 SAP Income Statement by month,[369] the remainder of the increase for Executive/Administrative Compensation appears to be due to a significant increase in monthly costs charged to DEO by DRS. From April 2006 – December 2006, monthly charges averaged between $500,000 and $600,000 in this account. This trend continued through July 2007, at which point the Executive/Administrative costs recorded in Account 923 increased to between $900,000 and $1.2 million per month for the period August 2007 – November 2007.

For the years 2002 through 2006, Executive/Administrative Compensation costs charged to DEO by DRS averaged $5,029,463 per year. The amounts charged in 2007 represent a 71% increase over this historical average and a 48.9% increase over the 2006 amount.

In response to Blue Ridge discovery seeking explanation of the increases to Executive/Administrative Compensation costs, the Company provided the following:[370]

[368] Response to Data Request BRCS-DWS-05-005.
[369] Response to Data Request BRCS-WF-02-14.
[370] Response to Data Request follow-up to BRCS-WF 04-01 and BRCS-DWS 05-05.

DRS EXECUTIVE BILLINGS
FOR THE YEARS ENDED 2007 and 2006

The reason for the increase in Executives in 2007 is due to the following:

Increase in Long-Term Incentive Plan Expense	$	14,846,040	(new plan began in 2006-2007)
Increase in Restricted Stock Amortization Expense		819,379	(new stocks granted in 2006-2007)
Increase in Short-Term Incentive Plan Expense		10,572,053	(based on 2007 earnings)
Increase in Executive Pension Settlements		2,017,703	(due to 3 executive retirements in 2007)
Increase in Consulting Expense		705,038	
Total increase in Executive/Admin	$	28,960,213	
Average EOG percentage of 2007 changes is 8.75%	$	2,534,019	

The Company's analysis of the increase to this category in 2007 shows that total DRS Executive Billings to the operating companies increased by $28,960,213, of which 8.75% of that total or $2,534,019 was billed to DEO. These increases were in Long Term Incentive Plan Expense, Restricted Stock Amortization Expense, Short Term Incentive Plan Expense, Executive Pension Settlements, and Consulting Expense. Based on the reasons provided by the Company for increases in these amounts (e.g., a new Long Term Incentive Plan began in 2006-2007 and 3 executive retirements in 2007, 2007 earnings), it appears that these increases to DRS executive billings for the year 2007 are items that may be unique to the year 2007 and would not occur in a typical year.

2. **Customer Service**

2007: $7,387,556
2006: $5,181,791
Increase: $2,205,764 or 42.6%

The DRS billings to DEO for Customer Service in 2007 increased by 42.6% over 2006 and increased by 83% over the Customer Service billings to DEO for the period 2002-2006. The Company indicates that Customer Service billings increased in 2007 due to the Company's response to Ohio Minimum Service Standards, which includes a requirement for Average Speed of Answer (ASA) in the Company's phone center of 90 seconds or less. In order to satisfy the ASA requirement of the Service Standards, DEO's call center staffing was supplemented by Virginia Power call agent support.[371]

3. **Miscellaneous**

2007: $1,760,984
2006: ($68,681)
Increase: $1,829,665

[371] Response to Data Request BRCS-DWS-05-006.

The Miscellaneous Expense billings fluctuated widely from year to year between 2002-2006, but the Miscellaneous billings for each year between 2002 and 2006 was significantly less than the Miscellaneous billings to DEO from DRS in 2007. During the previous five years Miscellaneous billings from DRS to DEO ranged from a low of a credit of $(402,538) in 2003 to a high of $193,009 in expense in 2004.[372] Blue Ridge sought an explanation for the Company for the 2007 increase in Miscellaneous costs in discovery, to which the Company responded as follows:

> In 2007, DEO's allocation of DRS Miscellaneous Expense includes increased expense of $2,612,582 for DEO's portion of the additional 2007 Annual Incentive Plan payouts accrued in December 2007 once company earnings were known offset by a $900,000 check received for Insolvent Insurance Company Claims settlements. The net of these values is an expense increase of $1,712,582.[373]

4. **Information Technology**

2007: $19,485,912
2006: $18,624,333
Increase: $861,578 or 4.6%

Between 2002 and 2006, the billings from DRS to DEO for Information Technology fluctuated relatively widely, ranging from $0 in 2002 to $18,624,333 in 2006. This resulted in an average annual Information Technology billing from DRS to DEO of $13,407,923 for the years 2003-2006.[374] The 2007 amount for Information Technology, therefore, is a 45% increase over the previous 5 year average. However, for 2007, the Information Technology category includes charges which were in previous years spread over three separate categories – (i) Information Technology, (ii) Client Services – Sol Center and (iii) Data Operations. Together, these three service categories totaled $20,094,444 in 2005 and $20,440,859 in 2004.[375] Thus, an apples-to-apples correlation would compare the 2007 Information Technology category of $19,485,912 to the average of the combined historic categories of Information Technology, Client Services – Sol Center, and Data Operations of $20,279,212 (average of years 2002-2005). Therefore, although the 2007 cost is greater than 2006, it is less than previous years and is in line with historical trend.

[372] See DEO's SAP-based income statements provided in response to WF 02-14 through December 2007. See also Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls*.
[373] Response to Data Request follow-up to BRCS-WF 04-01 and BRCS-DWS 05-05.
[374] This excludes the $0 billings for Information Technology in 2002.
[375] Workpaper *C(16)_WF-04-01_Account 923 Analysis.xls*.

Findings

Blue Ridge finds that the DRS costs charged to DEO for the year 2007 and, in turn, FERC Account 9923000 "Admin & General – Outside Services Employed" are significantly higher than in the previous 5 years. While the Company provided explanations for all increases, one concern remains. Without a full examination of the reasons and calculations behind the 2006/2007 incentive package, the 71% increase in Executive/Administrative Compensation seems excessive.

Conclusions and Recommendations

Blue Ridge recommends that the Commission may want to consider a more rigorous audit evaluation focusing on the Executive/Administrative Compensation package to determine the justification for the 71% increase over the 5-year historic average.

If, as a result of an audit of the Executive/Administrative Compensation package, the Commission determines the 2007 increase to be unjustifiable, the Commission may want to consider several options in this regard. One option would be to bring the test year amount more in line with the amount booked in 2006. This would result in a test year amount for Account 923 that is 2.6% greater than the 5-year average (2002-2006). Another option is to adjust the test year to reflect the historical trend observed in the data. The average percent change in year to year Account 923 amounts of +2.3%,[376] and if that average growth rate is applied to the test year amount a reduction of $5,804,088 would be necessary to the test year amount.[377] If the 5 year percent change average is used (instead of the six year average which includes the unusual increases observed in 2007), the average would be -0.513% and would result in a reduction in the test year amount of $7,258,851.[378] An additional option would be to adjust the test year to be in line with the 5-year (2002-2006) average Account 923 amount of $50,424,364. In this case a reduction to the test year amount of $8,284,891 is needed.

[376] % change 2003-2002 = -5.51%; % change 2004-2003 = -2.94%; % change 2005-2004 = +0.30%; % change 2006-2005 = +6.09%; and % change 2007-2006 = +13.53%.

[377] 2006 Account 923 = 51,715,706 + 2.3% = 52,905,167. Test year Acct 923 $58,709,255 – 52,905,167 = 5,804,088.

[378] 2006 Account 923 51,715,706 – 0.513% = 51,450,404. Test year Acct 923 $58,709,255 – 51,450,404 = 7,258,851.

Appendices

Appendix 1 – Documents Reviewed
Appendix 2 – Data Requests Submitted
Appendix 3 – Index to Workpaper Files

Appendix 1
Documents Reviewed

EAST OHIO GAS COMPANY DBA DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Documents Reviewed by BRCS

	Description	Filename	# of pages
1	In the matter of the application of The East Ohio Gas Company d/b/a Dominion East Ohio for authority to increase rates for its Gas Distribution Service.	Application for Dominion.pdf	150
2	Application, Volume 1, alt. reg. exhibits, sections A-D and F schedules, and schedules S-1- S-3 filed by B. Klink on behalf of East Ohio Gas Company dba Dominion East Ohio. (part 1 of 2).	Application for Dominion Vol. 1 part 1.pdf	125
3	Application, Volume 1, continued. (part 2 of 2)	Application for Dominion Vol. 1 part 2.pdf	122
4	Application, Volume 2, Section E Schedules. (part 1 of 3)	Application for Dominion Vol. 2 part 1.pdf	150
5	Application, Volume 2, continued. (part 2 of 3)	Application for Dominion Vol. 2 part 2.pdf	150
6	Application, Volume 2, continued. (part 3 of 3)	Application for Dominion Vol. 2 part 3.pdf	165
7	Application, Volume 3, Schedule S-4.1	Application for Dominion Vol. 3 part 1.pdf	188
8	Application, Volume 4, Schedule S-4.2 . (part 1 of 2)	Application for Dominion Vol. 4 part 1.pdf	200
9	Application, Volume 4, continued. (part 2 of 2)	Application for Dominion Vol. 4 part 2.pdf	185
10	Direct testimony and exhibits of Dominion East Ohio, filed by M. Whitt. (Part 1 of 3)	Direct Testimony Dominion part 1	201
11	Direct testimony continued. (Part 2 of 3)	Direct Testimony Dominion part 2	201
12	Direct testimony continued. (Part 3 of 3)	Direct Testimony Dominion part 3	51
13	4903.02 Examination of Witnesses - production of records	Lawriter - ORC - 4903.02 Examination of witnesses - production of records..pdf	1
14	4903.03 Examination of records	Lawriter - ORC - 4903.03 Examination of records..pdf	1
15	4905.03 General Supervision	Lawriter - ORC - 4905.06 General supervision..pdf	1
16	4905.15 Reports and accounts	Lawriter - ORC - 4905.15 Reports and accounts..pdf	1
17	4905.16 Copy of contract may be required by commission	Lawriter - ORC - 4905.16 Copy of contract may be required by commission..pdf	1
18	4909.15 Fixation of reasonable rate	Lawriter - ORC - 4909.15 Revised Code.pdf	10
19	4909.18 Application to establish or change rate	Lawriter - ORC - 4909.18 Revised Code.pdf	3

EAST OHIO GAS COMPANY DBA DOMINION EAST OHIO
Case No. 07-0829-GA-AIR
Documents Reviewed by BRCS

	Description	Filename	# of pages
20	Notice of Sutbstitution of schedule for Case No. 07-829-GA-AIR	Dominion Revised Schedules.pdf	35
21	Ruling on Test Year and Waivers for Case No. 07-829-GA-AIR	Dominion Ruling on Test Year and Waivers.pdf	4
22	Summary of The East Ohio Gas Company Case No. 93-2006-GA-AIR	Opinion and Order DOM_11-3-94.pdf	132
23	Motion of East Ohio Gas D/B/A Dominion East Ohio to Establish Test Year and Date Certain and For Waivers fromCertain Standard Filing Requirements	DEO Motion for Test Yr and Waivers.pdf	10
24	Entry Before the PUCO For Case No. 07-829-Ga-AIR	8-15-07 Approval of TY and Waivers.pdf	4
25	Gas Intrastate Annual Report of East Ohio Gas Company to the PUCO	DOM 1998 FERC Form 2.pdf	198
26	Dominion Gas Company 07-0829-GA-AIR Plant Analysis from Anual Reports	East Ohio Plant.xls	12
27	Report to the PUCO on the Management and Performance Audit of Gas Purchasing Practices and Policies of East Ohio Gas Company Case No. 07-219-GA-GCR	Mgt Perf Report Gas Purchase 07-219.pdf	125
28	Staff Reprot of Investigation - Application of West Ohio Gas Company Case No. 82-1458-GA-AIR pages 1-12	PUCO Staff Report of Investigation pages 1-12.pdf	18
29	Testimony Index of Dominion's Direct Testimony	Dominion Direct Testimony Index 071218.doc	1